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JUL 78 A I MCCONE, J D RUBY, W V MACKEWICZ N68305-77-C-0021

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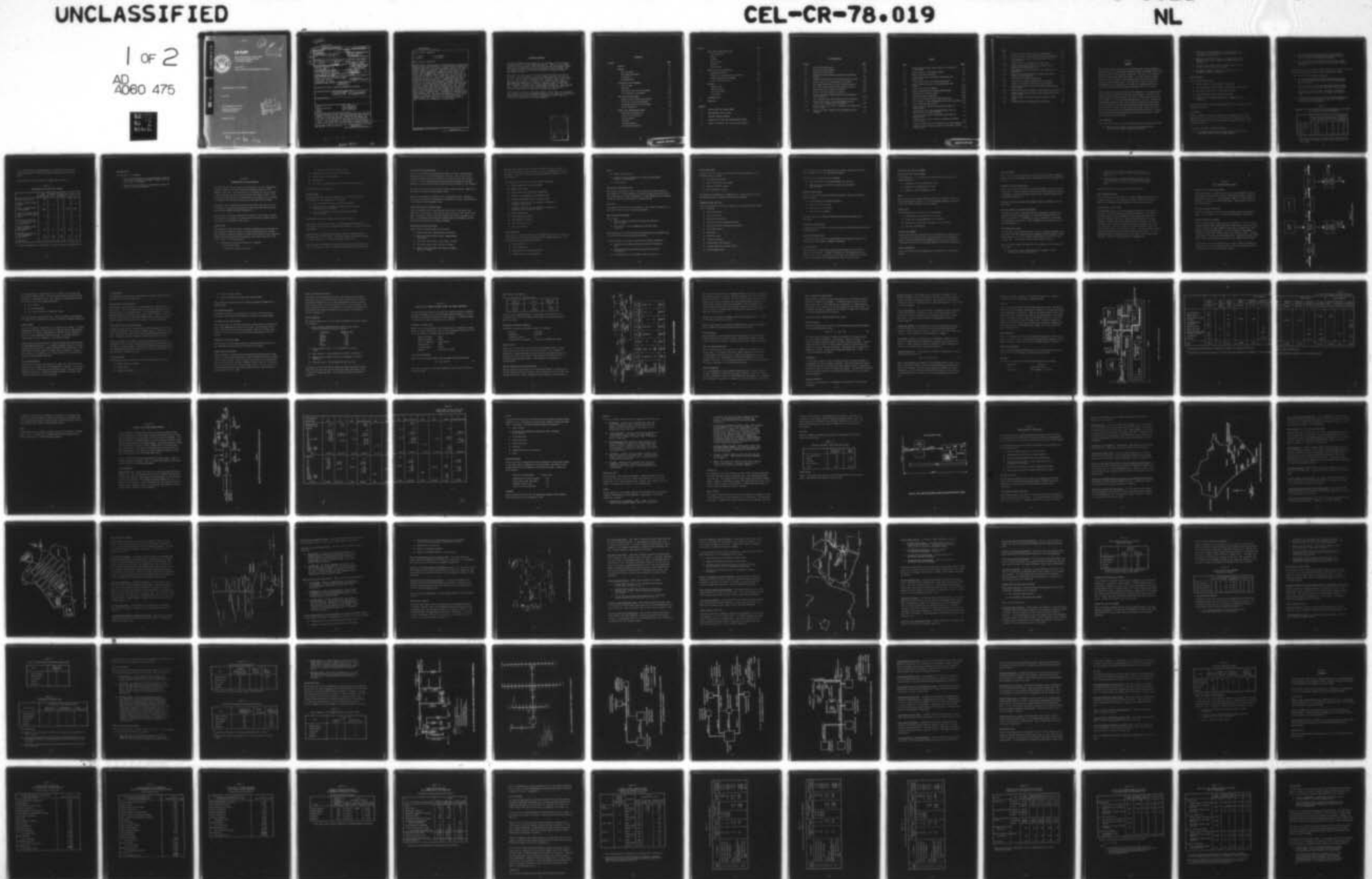

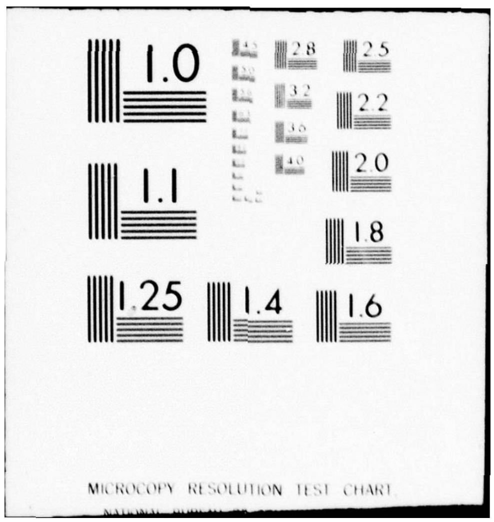
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CIVIL ENGINEERING LABORATORY
Naval Construction Battalion Center
Port Hueneme, California

Sponsored by
NAVAL FACILITIES ENGINEERING COMMAND

GASIFICATION AT NAVY BASES

July 1978

An Investigation Conducted by
BECHTEL CORPORATION
San Francisco, California

N68305-77-C-0021

18 CEL

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The work described in this report was performed under Contract N68305-77-C-0021 with the Civil Engineering Laboratory (CEL) at the Naval Construction Battalion Center at Port Hueneme, CA. The title of the contract was "Coal Gasification Feasibility Study." Coal gasification is recognized as a way to produce a clean burning boiler fuel from coal within acceptable environ- CONT'

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mental limits. The study was to assist the Navy in determining how coal might best be utilized, by comparing gasification with central direct coal-fired boiler systems at each of five bases. Bechtel showed in a previous study for CEL that gasification plants could be economically attractive at Navy bases. Gas from a plant producing 250 x 10^6 Btu/hr with a load factor of 90 percent was shown to have a lower life cycle cost than continued use of fuel oil. This second study examined plants as they would actually be operated. A conceptual design study comparing coal gasification with central direct coal-fired boilers at five bases was performed. The major finding at the five bases studied was that actual load factors are 36 percent or below. Because gasification plant capital costs are high, the reduced load factor makes gasification less attractive. The results showed that coal gasification offers lower life cycle costs than central coal-fired boilers at only one of the bases studied, Camp Pendleton. Installations at Mechanicsburg, PA; Great Lakes, IL; and at Norfolk and Quantico, VA, were not shown to be favorable candidates for coal gasification. A design optimization study for a coal gasification plant at Camp Pendleton was recommended as the next step.

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The authors thank the contract monitor, D.E. Williams, of the Civil Engineering Laboratory, for his review and comments. Others at Port Hueneme provided vital information: Harry Taplin of the Navy Environmental Support Office gave invaluable data on boilers installed at the five bases, and Ray Bergmann of CEL gave information on sources of energy and facility data about the bases.

Personnel at the five bases visited were helpful with their time and information. These included S. A. Corrao at Camp Pendleton; Ron Yates and Lt. H. D. Ellis at Mechanicsburg Navy SPCC; Charley Harrison at Great Lakes NTC; Lt. James L. Walker at Norfolk; and J. Alexander, Wayne Burke, W. W. Patterson, and Vaughn Peak at Quantico. Also Bob Stimeare at NORTHDIV, NAVFACENGCOM provided data on a recent engineering study for Great Lakes NTC. Personnel at WESTDIV also provided useful information. These included Wayne Lorimer on operating costs, John De Becker on Camp Pendleton soil wetness, and Bob Chant on oversizing of boilers and heaters.

Bechtel thanks the major vendors who provided technical and cost information: Davy Powergas gave data on the Winkler gasifier; Foster Wheeler and Combustion Engineering provided data on boilers; and Research Cottrell, FMC, and Chemico gave information on stack gas scrubbers.

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Section 1

SUMMARY

The work described in this report was performed under Contract N68305-77-C-0021 with the Civil Engineering Laboratory (CEL) at the Naval Construction Battalion Center at Port Hueneme, California. The title of the contract was "Coal Gasification Feasibility Study." Coal gasification is recognized as a way to produce a clean burning boiler fuel from coal within acceptable environmental limits. The study was to assist the Navy in determining how coal might best be utilized, by comparing gasification with central direct coal-fired boiler systems at each of five bases.

Bechtel showed in a previous study for CEL (Reference 1) that gasification plants could be economically attractive at Navy bases. Gas from a plant producing 250 x 10^6 Btu/hr with a load factor of 90 percent was shown to have a lower life cycle cost than continued use of fuel oil. This second study examined plants as they would actually be operated at Navy bases. The major finding at the five bases studied was that actual load factors are 36 percent or below. Because gasification plant capital costs are high, the reduced load factor makes gasification less attractive. However, at one base studied gasification appears more attractive than a central direct coal-fired boiler system.

WORK PERFORMED

Work under the present contract was performed in the following five areas:

- Determining the required sizes for gasification and central coal boiler plants at each of five bases

- Preparing a conceptual design of a central direct coal-fired boiler plant including a stack gas scrubber and electrostatic precipitator

- Adapting a conceptual design of a coal gasification plant prepared under Contract N68305-76-C-0009 (described in Reference 1)

- Preparing a conceptual design of a plant making both gas and the storable liquid fuel methanol

- Calculating capital, operating, and life cycle costs of alternative systems at each base

BASES CONSIDERED

The five bases studied were:

- Marine Corps Base, Camp Pendleton, California
- Navy Ships Parts Control Center, Mechanicsburg, Pennsylvania
- Navy Public Works Center, Great Lakes, Illinois
- Navy Public Works Center, Norfolk, Virginia
- Marine Corps Development and Education Command, Quantico, Virginia

Each base was visited. Data on heat loads, fuel use, gas piping and steam piping were obtained.

CONCLUSIONS

Table 1-1 compares costs of alternatives at each base in terms of the present value of each 10^6 Btu of heat transferred in existing heat loads. This unit present value is the best measure of comparative costs. It is defined in Section 7.

Inferences from Table 1-1 are as follows:

- Gasification plant is more economical than a central direct coal-fired steam plant only at Camp Pendleton

- A plant making both gas and methanol is more economical than the direct coal-fired boiler at Camp Pendleton, but not more economical than simple gasification

- A central direct coal-fired boiler system is more economical than continued use of fuel oil at Great Lakes, Norfolk, and Quantico

Camp Pendleton has the following features which make a central direct coal-fired boiler system more expensive than a gasification system:

- The heat loads are widely dispersed

- No steam piping system currently exists linking all loads to a central steam plant; 60 miles of new, large-diameter pipe are required

- The pipe runs are so long that substantial thermal losses occur, even with buried pipes with 5-inch-thick insulation

- The number of loads is large. Each must be connected to the large-diameter pipes by small diameter distribution lines

- A large number of loads will require expensive retrofitting of heaters to operate on steam. There are 4,000 family housing units at Camp Pendleton

Table 1-1

TRANSFERRED HEAT UNIT PRESENT VALUES OF ALTERNATIVES AT FIVE BASES*
(Fourth Quarter 1977 Dollars/10^6 Btu)

	Gasification	Gas and Methanol	Direct Coal Fired Boiler	Fuel Oil, No New Equipment
Camp Pendleton	4.38	4.46	5.26	2.64
Mechanicsburg	5.66	—	3.41	2.64
Great Lakes	3.58	—	2.03	2.64
Norfolk	2.56	—	1.79	2.64
Quantico	2.85	—	2.07	2.64

*Note that the costs are life cycle present values, with the future heavily discounted. They are not current costs per million Btu.

Of the capital costs for Camp Pendleton, two dollars must be spent on piping and retrofit for each dollar spent on the central boiler plant itself.

Characteristics of the five bases are summarized in Table 1-2.

Table 1-2

CHARACTERISTICS OF NAVY BASES STUDIED

	Camp Pendleton	Mechanics-burg	Great Lakes	Norfolk	Quantico
Square miles of area	200	1	3	10	100
Number of large heating plants*	326	73	3	4	13
Number of homes served by new systems	4,000	0	0	1,100	900
Miles of new large steam pipe required for boiler option	57	3	3	5	21
Miles of new large gas pipe required for gasification option	33	3	3	6	16
Annual average current fuel consumption, 10^6 Btu/hr	103	43	102	269	158
Estimated peak current fuel consumption, 10^6 Btu/hr	320	308	380	750	458
Load factor	.32	.14	.27	.36	.34

* Plants containing one or more boilers or heaters larger than 600,000 Btu/hr.

RECOMMENDATIONS

The following is recommended:

- A more detailed design of a coal gasification plant for Camp Pendleton should be performed to improve the accuracy of the cost estimate
- Decentralized coal boilers at Camp Pendleton should be studied as a third alternative

Section 2

INTRODUCTION AND BACKGROUND

The work described in this report was performed for the Civil Engineering Laboratory (CEL) at the Naval Construction Battalion Center at Port Hueneme, California. Coal gasification is recognized as a way to produce a clean burning boiler fuel from coal within environmental limits. This study has assisted the Navy in determining how coal might best be utilized, by comparing coal gasification with direct coal-fired boiler systems.

The present study utilized the technical description and costs for a 250 x 10^6 Btu/hr coal gasification plant that was prepared for CEL by Bechtel under Contract N68305-76-C-0009 (Reference 1).

This section of the report describes the contract scope of work, the work plan followed in the study, the study basis and initial screening, and the structure of the remainder of the report.

SCOPE OF WORK

The objectives of the study were to perform comprehensive cost analyses and site specific feasibility studies for central coal gasification systems, and to prepare a baseline design of a direct-fired system for cost comparison. Bechtel met these objectives by carrying out the tasks called for in the scope of work. The tasks included:

- Defining the alternative systems to be compared
  - The baseline plant
  - A central gas plant for retrofit

- A central gas plant for central steam

- Conducting site specific feasibility studies
- Comparing costs of alternatives
- Reporting work
- Performing a supplementary task on a methyl fuel alternative

These tasks are described below.

Baseline System

A baseline plant with a coal consumption rate of 250×10^6 Btu/hr was established for cost comparisons. It included:

- A new conventional central coal-fired steam plant
- Pollution control equipment for removal of sulfur oxides and particulates as required
- A steam distribution system of insulated underground pipes in conduits

The equipment chosen was lowest cost and state-of-the-art.

Existing oil and gas-fired boilers at the bases and decentralized coal-fired boilers were considered abandoned and, therefore, not part of the baseline design.

The capacities of baseline plants needed at each of the bases would be different from 250×10^6 Btu/hr. Therefore, Bechtel established a method for finding the costs of the baseline plant at each base.

The coal used for performance calculations was also used in the previous study. The nature of the coal available to each base also was determined.

Central Gas Plant for Retrofit

The cost of a central coal gasification plant to provide a clean burning gaseous fuel from coal was estimated for each base. The costs of retrofitting existing oil and gas-fired boilers to burn this gas were included. The cost of a new basewide gaseous fuel distribution system was included whenever a natural gas distribution system was not available or was inadequate.

The plant costed at each base had the required capacity and was compared with the cost of a similarly sized baseline plant.

Bechtel also examined the economic life of installed boilers, considering age, type and frequency of maintenance, availability of parts, and maintenance costs compared with replacement costs.

Central Gas Plant for Central Steam

Bechtel considered also an appropriately sized central coal gasification plant that could produce a clean burning fuel for use in a new central steam plant at each base, with a steam distribution like that in the baseline design. Its elimination from detailed consideration is discussed in the part of this section dealing with initial screening.

Site Specific Feasibility Study

Bases visited and analyzed were the following:

- Marine Corps Base, Camp Pendleton, California
- Navy Ships Parts Control Center, Mechanicsburg, Pennsylvania
- Navy Public Works Center, Great Lakes, Illinois
- Navy Public Works Center, Norfolk, Virginia
- Marine Corps Development and Education Command, Quantico, Virginia

The bases were ranked in order from most suitable to least suitable for central coal gasification on the basis of cost. A recommendation was made on whether a central coal gasification system should be installed for test and evaluation.

In carrying out the feasibility study, Bechtel considered:

- Annual quantitative fuel requirement
- Type of fuel in use
- Current and future local coal availability
- Capacity of and demand for installed boilers
- Estimated remaining life of installed boilers
- Estimated remaining life and adequacy of capacity of installed steam system
- Estimated remaining life and adequacy of capacity of installed fuel distribution system
- Coal transportation
- Coal handling facilities
- Ash handling facilities
- Coal storage facilities
- Space availability

Cost Comparisons

The costs were computed according to the methods and criteria of References 1, 2, and 3 so that options or systems could be compared directly. Costs are presented in the following four ways:

- Total expenditure
- Yearly expenditure
- \$/million Btu of fuel heating value
- \$/million Btu of steam generated

Reports

- Monthly letter reports
- Technical review meetings every 45 days with government technical representatives
- A final report

Methyl Fuel Supplementary Task

CEL funded a supplementary task to study a methyl fuel plant sized for Camp Pendleton. Bechtel prepared a conceptual design and costed a methyl fuel plant based on current technology. It was compared with the baseline design and with the gasification for retrofit option.

WORK PLAN

To accomplish the tasks in the statement of work, Bechtel carried out the work plan described in the following paragraphs.

Base Information Gathering

CEL provided:

- FACSO listings of significant boilers and furnaces at the five bases
- DEIS reports on fuel consumption at the three Navy facilities

The Engineering Field Division Offices provided general development maps for the five bases and some miscellaneous data.

A visit was made to each base to gather the following information:

- Confirming and supplementing boiler and fuel consumption data
- Providing existing steam and gas distribution system descriptions
- Providing data on soil, weather, other utilities, etc.

Plant Sizing Study

For each of the five bases, the necessary sizes were computed for the following types of systems:

- Coal gasification plants
- Direct coal-fired boiler plants
- Steam distribution systems
- Gas distribution systems

The sizes were determined by a combination of a total installed capacity method and the fuel consumption and weather data method.

Component Design and Costs

Cost versus capacity curves were prepared after consultation with vendors for the following:

- Coal-fired boilers
- Gas-fired boilers
- Winkler coal gasifiers
- Coal receiving and preparation plants
- Gasification plant interconnecting piping
- Gas storage spheres
- Steam pipe
- Plastic gas pipe
- Stack gas scrubbers
- Electrostatic precipitators
- Cyclone particulate removal devices
- Waste disposal ponds

Bechtel already had on hand proprietary cost versus capacity data for all other components of the coal gasification plants.

Costs were also estimated for the following:

- Retrofitting boilers and home heaters for coal gas
- Replacing oil or gas-fired air heaters with steam-air heat exchangers

Baseline System Design

A direct coal-fired steam plant baseline conceptual design was prepared, which included:

- Coal handling and preparation system
- Coal-fired boiler system
- Electrostatic precipitator
- Lime stack gas scrubber

The design involved preparing flowsheet and determining equipment and interfaces.

Gasification Plant Design

A flowsheet developed under the previous study was already encoded in Bechtel's Program GASPLANT.

Methyl Fuel Plant Design

A methyl fuel plant sized for Camp Pendleton was designed, using gasification and shift and methanol synthesis technology.

Cost Comparisons

Direct-fired coal steam plants and gasification plants were costed for each of the five bases. A methyl fuel plant for Camp Pendleton was also costed. The costs of alternatives at each base were compared. The alternative of no investment and continued use of fuel oil was also made.

STUDY BASIS AND INITIAL SCREENING

Furnace Input and Output Ratings

The following ways of describing boiler performance were used and are roughly equivalent:

- Consumption of 250 x 10^6 Btu/hr of fuel
- Production of 200,000 lb/hr of steam
- Transfer of 200 x 10^6 Btu/hr of heat

Coal

The coal used in the previous study was used for the central coal-fired steam plant design in Section 5. It is considered adequately representative of the coals available to the five bases.

Energy Costs

The following prices were used in cost comparisons:

- Coal $25/short ton, delivered to the base
- Electricity at Camp Pendleton, 34.5 mills/kW hr
- Electricity at the other four bases, 34.2 mills/kW hr
- Fuel oil, \$2.90/10^6 Btu

Criteria for Ranking

Cost was the only factor that was used in determining the ranking of the five bases as to suitability for coal gasification in the feasibility study. All other ranking factors mentioned in the scope of work were converted into costs and are included implicitly in the cost comparisons.

Space Availability

Each of the five bases had adequate space available for a gasification plant.

Coal Availability

Each of the five bases could obtain coal from a source within a reasonable distance, and at a reasonable price. All had rail spurs for receiving coal by train.

Equipment and Piping System Life

Boilers and heaters installed before 1950 were assumed too old for use in a new system. Bechtel experience indicates that high operating costs with old equipment outweigh replacement capital costs, after the 28 year life recommended by Reference 4.

Existing steam piping systems were assumed to have an indefinite life in this study.

Central Gas Plant for Central Steam Plant

It became clear early in the study that this alternative could never be competitive, since it would always cost more than the gasification for retrofit alternative. Accordingly, it was not included in the detailed cost comparisons of Section 7. Brief remarks on the alternative are provided in Appendix A.

Sulfur Emissions Limits

For this study, it was assumed that the coal at all bases contained 2 percent sulfur, and that emission control equipment would be needed to reduce sulfur emissions to 1.2 lb of sulfur dioxide (SO_2) per 10^6 Btu of coal heating value. This amounts to 70 percent removal of sulfur.

These following assumptions appeared to be reasonable for the purposes of this study:

- Federal SO_2 control regulations may be extended to small industrial sources in the future.

- Currently enacted federal regulations are forcing use of emission control equipment even by utilities burning low sulfur coal
- The sulfur removal equipment provided can easily reach high percentages of removal without significantly higher cost, for both gasification plants and coal-fired boiler plants

Appendix B discusses federal and local pollution limits.

Cost Estimate Accuracies

The cost estimates in this report are "order of magnitude" estimates with a probable accuracy of plus or minus 25 percent. This is the accuracy expected in conceptual design studies such as those in this report.

THE STRUCTURE OF THIS REPORT

The remaining sections of this report provide details of the results of the study. Section 3 describes the modules included in a coal gasification plant such as that considered in the previous study (Reference 1). Section 4 presents a design of a methyl fuel plant sized to fit Camp Pendleton. A methyl fuel plant operating with a 90 percent load factor was expected to be competitive with gasification operating with a 32 percent load factor. Section 5 presents the baseline design, a 250×10^6 Btu/hr central direct coal-fired boiler plant. Section 6 presents existing and required new facilities for the alternatives at each base. Section 7 compares capital, operating, and life cycle costs of the alternatives at each base. Section 8 contains Bechtel's recommendations.

Section 3

COAL GASIFICATION PLANTS

MODULES IN COAL GASIFICATION PLANTS

Gasification plants described in this study contain a number of modules. These modules are described in detail in this section and are costed out separately in Section 7. A block diagram, Figure 3-1, shows the major modules of a typical coal gasification plant. The functions of each one are described below.

Coal Receiving and Preparation

The coal is shipped by rail or truck and stored on site in coal piles or silos. It is crushed to size as needed and conveyed to the gasifiers.

Gasification and Gas Cooling

The gasification process takes place in the gasifiers. This is a partial oxidation process that converts the nonash constituents of coal into a gas. This gas is made up of the flammable constituents, hydrogen (H_2), carbon monoxide (CO), and methane (CH_4). It also includes the nonflammable diluents, nitrogen (N_2), carbon dioxide (CO_2), and water (H_2O). Polluting constituents in the gas include hydrogen sulfide (H_2S) and carbonyl sulfide (COS). These pollutants must be reduced to low levels by gas treatment.

After the gas leaves the gasifiers it is cooled to ambient temperature in preparation for the gas treatment process. This is accomplished through steam generation followed by gas wash cooling.

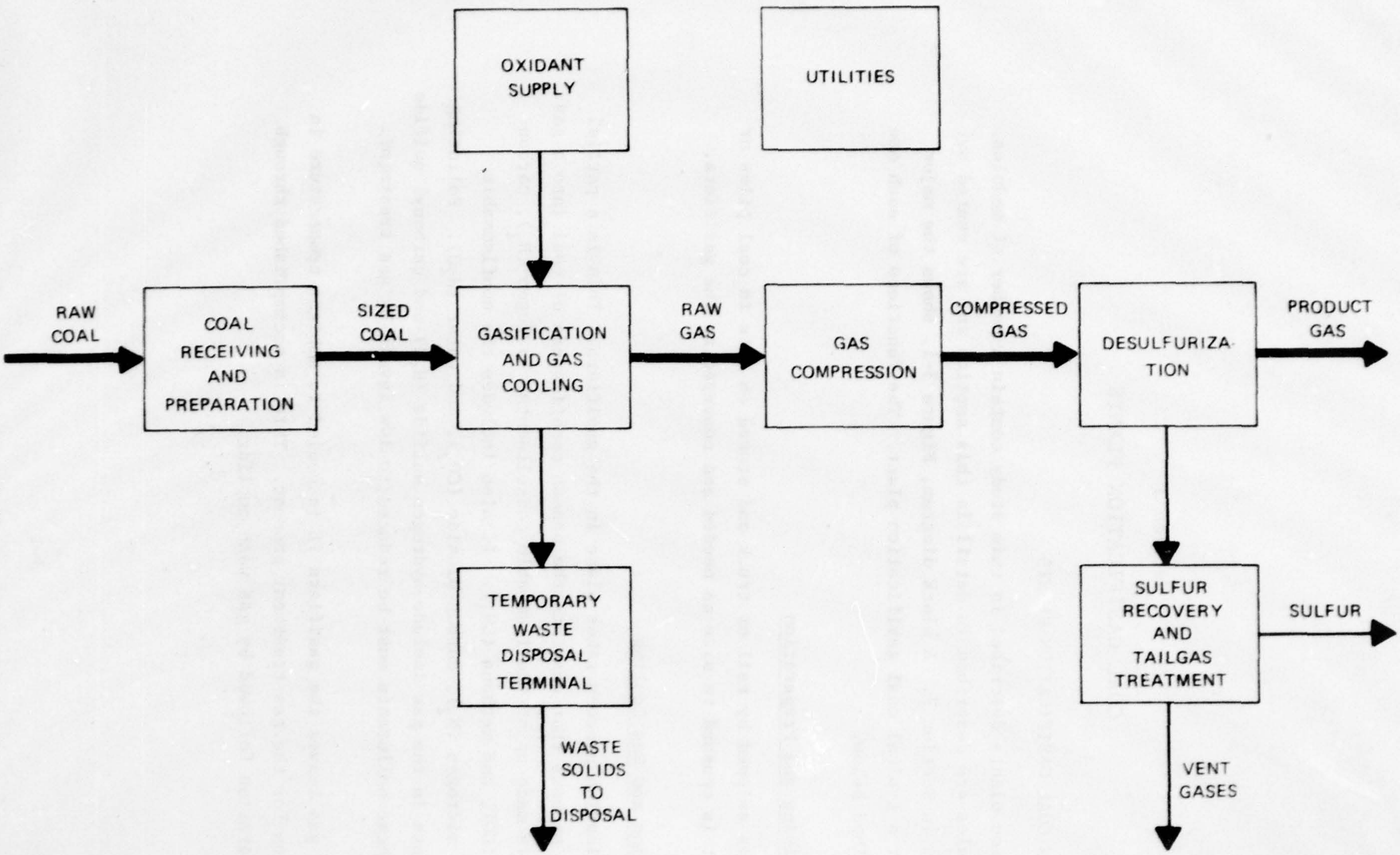


Figure 3-1
COAL GASIFICATION PLANTS

For steam generation, a waste heat boiler is used to cool the gas from approximately 2000 to 350°F. The heat extracted from the gas can be used to generate a superheated steam. This steam can be used entirely within the plant for one of the following purposes:

- As a reactant
- As a heating medium
- As a source of power for mechanical drives

Next, the gas wash cooling takes place. Here the residual entrained ash is removed and the temperature of the gas is reduced to ambient temperature.

Oxidant Supply

Coal can be gasified using either air or oxygen as the oxidant. Air blown gasification produces a low Btu gas with a heating value of approximately 130 Btu/scf. It contains approximately 50 percent nitrogen diluent and burns at a lower temperature than natural gas. To use this method of oxidant supply, an air compressor or air blower is needed.

Oxygen blown gasification produces a medium Btu gas with a heating value of approximately 300 Btu/scf. It contains negligible amounts of nitrogen diluent and often burns at a higher temperature than natural gas. To use this method of oxidant supply, an oxygen plant is required. A typical plant contains air compressors, a cold box in which air is liquified and distilled, and an oxygen compressor.

Waste Solids Disposal

Entrained ash is removed from the gas by a water wash. The ash must be disposed of in a manner that is environmentally acceptable. It is usually placed in piles or ponds near the gasification site, or within trucking distance of the site. A temporary disposal terminal at the site holds the wastes until they can be trucked away.

Gas Compression

Gas compression is required to raise the gas to delivery pressure which is 150 psia for the plants studied here.

Desulfurization and Dehydration

Desulfurization and dehydration are accomplished by a single physical solvent process. The gas is desulfurized to lower total emissions from fuel and vent gases to an acceptable level. It is then dehydrated to remove H_2O that contains residual H_2S and can lead to pipe corrosion. The single physical solvent process selectively removes most of the H_2S from the gas and allows most of the CO_2 and COS to remain. It also removes H_2O.

Sulfur Recovery and Tail Gas Treatment

A sulfur recovery process converts gaseous sulfur compounds into an environmentally acceptable form, such as elemental sulfur. Typically, a Claus plant is used for the conversion by partial oxidation and subsequent reaction. The sulfur produced is stored in liquid form and can be sold.

Tail gas treatment is necessary to bring the sulfur emissions from the Claus plant to an acceptable level as the gases from the plant may contain 5 percent of the entering H_2S. A Shell Claus Offgas Treatment (SCOT) plant will hydrogenate the tailgas, extract most of the H_2S, and finally incinerate and vent the residual tail gas.

Utilities Systems

The utilities systems modules serve all the other modules and include:

- Boiler feedwater treatment
- Cooling tower
- Cooling water pumps

- Electrical supply panels

- Vacuum condensers for oxygen plant steam turbines

These modules are generally used for utilities systems in chemical processing plants.

Interconnecting Piping

The modules described in this section are priced by unit in Section 7. Piping that interconnects these modules is costed as a separate module.

EFFICIENCY OF COAL GASIFICATION

The gas emerging from the gasification and cooling usually contains 82 percent of the combustion heat from the coal feed. For the plants in this study, outside electricity will be purchased. When this is taken into account, the efficiency of the coal gasification process may be only 60 percent.

TECHNOLOGY SELECTED FOR BASES

Several types of gasification plants were considered before selection of the technology that would apply to the needs of the bases.

Oxygen Blown Gasification

Bechtel showed in a previous study that medium Btu gas burns with ratings equal to or higher than natural gas or fuel oil whereas low Btu gas usually leads to lower ratings. Because natural gas and fuel oil are used in the boilers and heaters on the bases considered in this study, it is important that the coal gas have the same heat output rating. For this reason, oxygen blown gasification, which produces medium Btu gas, was selected for boiler retrofit in this study.

Winkler Fluidized Bed Gasifier

The Winkler fluidized bed gasifiers have been chosen for these plants. These gasifiers were selected because the gas produced does not contain condensible contaminants, such as heavy hydrocarbons; the water used to wash out particulates from the gas will be free of oils and phenols; and plants using these gasifiers are slightly less expensive than those using the entrained flow gasifiers studied as an alternate in the previous contract (Reference 1).

DESIGN PARAMETERS

The design parameters for the five plants discussed in this study include the following:

- Coal: Although compositions will vary by area, Eastern Kentucky bituminous was taken as typical:

Constituent	Weight Percent
Carbon	60.47
Hydrogen	3.70
Oxygen	5.96
Nitrogen	1.41
Sulfur	2.00
Ash	21.46
Moisture	5.00

- Sulfur emissions limit: 1.2 lb $SO_2/10^6$ Btu coal heat content
- Plant capacity: varies between 120 and 750 x 10^6 Btu/hour
- Number of plant trains: one or two, depending on required redundancy
- Plant use factor: varies between 14 and 35 percent

Calculations of the flows and the capital and operating costs of plants with different capacities and use factors have been facilitated by use of Bechtel's Program GASPLANT. This computer program is described in Appendix C.

Section 4

METHYL FUEL MANUFACTURING PLANT FOR CAMP PENDLETON

A plant that produces fuel in a gas and in a liquid form such as methanol has major advantages over a plant that manufactures gas alone — it can be operated on a continuous basis and at full capacity. A conceptual design of a methyl fuel plant is described in this section.

PROPERTIES OF METHYL FUEL

Methyl fuel is the name given to the liquid mixture of methanol and small amounts of higher alcohols that result from a catalyzed reaction of CO and H_2. Some properties of methyl fuel are as follows:

Chemical formula:	CH_3OH
Molecular weight:	32.04
Heat of combustion:	10,258 Btu/lb
Boiling point:	148°F
Freezing point:	-143°F
Density:	49.4 lb/ft^3 at 68°F

OUTLINE OF THE PROCESS

Methyl fuel can be manufactured from any medium Btu gas by reaction:

$$CO + 2H_2 = CH_3\ OH \tag{1}$$

Some basic parameters of the plant designed for this study are described on the next page.

Plant Products and Capacity

These are shown in the following table:

Mode of Operation	Products	Capacities, 10^6 Btu/hr
Gas Only	Gas	140
Gas and Liquid	Gas Liquid	$\left.\begin{matrix}68\\62\end{matrix}\right\}130$

In the process of making methanol, a percentage of the energy is lost, leaving the 130 x 10^6 Btu/hr capacity shown above for the gas and liquid mode of operation.

Conditions for Methanol Synthesis

Conditions for methanol synthesis include the following:

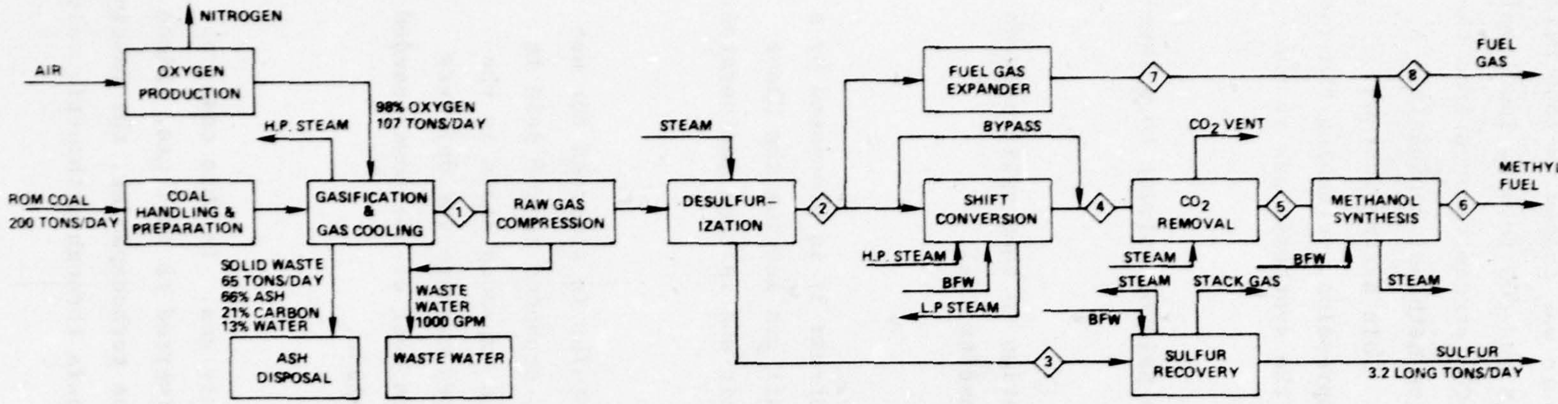
Pressure:	1500 psig
Temperature:	450-550^{o}F
H_2/CO molar ratio:	2.2
Allowed sulfur components:	0.1 parts per million by volume

PROCESS DETAILS

Figure 4-1 is a flow sheet for the methyl fuel synthesis plant. Stream 1, Cooled Raw Gas, has a heat flow of 140 x 10^6 Btu/hr. Coal handling and preparation, oxygen production, gasification, and ash disposal modules are identical in function with those in the gasification plants of Section 3, and will not be discussed further. The remainder of the modules are described below.

Raw Gas Compression and Desulfurization

Raw gas from the cooling train of the gasification module is compressed and then scrubbed with Selexol solvent to remove essentially all of the COS, H_2S, and H_2O in the gas. Because scrubbing is more efficient at high pressures



STREAM NUMBER	1	2	3	4	5	6	7	8
STREAM DESCRIPTION / STREAM COMPONENTS LB MOLES/HR	COOLED	PURIFIED GAS	ACID GAS	CO_2 - RICH SYNGAS	SYNTHESIS GAS	METHYL FUEL PRODUCT	DEPRESSURIZED FUEL GAS	FUEL GAS PRODUCT
HYDROGEN	541	541		406	406		215	297
CARBON MONOXIDE	439	439		185	185		174	199
CARBON DIOXIDE	250	211	39	208	2.5		83	84
WATER	41		1	0.5	0.5	0.5		
METHANE	46	46		28	28		18	46
NITROGEN	14	14		8	8		6	14
METHANOL								
HYDROGEN SULFIDE	9.9	0.00014	9.7			187.2		
CARBONYL SULFIDE	0.4	0.025	0.35					
TOTAL LB MOLES/HR	1341	1251	50.1	836	630	188	496	640
TOTAL LB/HR	26,601	23,786	1,910	15,825	6,783	5,999	9,410	10,396
TEMPERATURE, °F	104	100	100	100	100	130	86	96
PRESSURE, PSIA	35	1,500	30	1,480	1,450	50	40	40

Figure 4-1 METHYL FUEL BLOCK DIAGRAM

and less steam is required, the scrubbing pressure was chosen as 1500 psig, the methanol synthesis pressure. Removal of H_2S and COS to very low levels in this step makes it unnecessary to treat the CO_2 stream removed from the synthesis gas by the CO_2 removal unit just before methanol synthesis. A better sulfur recovery scheme is then possible. This arrangement was judged better than splitting the gas before compression, scrubbing the fuel gas at 150 psia, and removing H_2S and COS from the synthesis gas at the same time as CO_2 removal.

H_2O removal is carried out automatically by the Selexol solvent to a level of 150 parts per million by volume.

Purified gas (Stream 2) leaving the desulfurization is then split between gas for methanol synthesis and gas for direct use as fuel.

Sulfur Recovery

The gas removed by desulfurization (Acid Gas, Stream 3) is processed by a standard Claus plant to produce sulfur. The tail gas leaving the Claus plant is further processed by a SCOT process unit and is then incinerated.

Fuel Gas Pressure Reduction

Gas at 1500 psig with a heat flow of 55×10^6 Btu/hr is diverted for use as fuel gas. It is heated with steam to 300^oF, expanded to 246 psia in a turboexpander, then heated again to 300^oF, and expanded again in the second stage of the turboexpander to the required average gas delivery pressure of 40 psia. The turboexpander provides most of the power needed by CO_2 recycle compressor in the desulfurization plant.

Gas Only Operation

It is also possible to use the plant to make only gas. In this case, up to 140×10^6 Btu/hr of medium Btu gas can be diverted to fuel gas. Since only 55×10^6 Btu/hr of gas can pass through the turboexpander, the remaining 85×10^6 Btu/hr of gas must be expanded to 40 psia through a throttle valve.

Gas to Synthesis of Methyl Fuel

When operating to produce both gas and methanol, 85 x 10^6 Btu/hr of gas is directed to synthesis of methanol. To adjust the H_2/CO ratio to the required value, part of the synthesis gas is subjected to a shift reaction. The balance of the synthesis gas is then blended with the shifted gas. For a synthesis gas with the composition of Stream 2 in Figure 4-1, 45 percent should pass through the shift converter.

Subsequent steps in methanol manufacture follow.

Shift Conversion

The shift conversion unit allows a reaction between steam and carbon monoxide to produce hydrogen and CO_2:

$$H_2O + CO \rightarrow H_2 + CO_2 \quad (2)$$

The steam flow is regulated to produce the desired ratio between H_2 and CO for the methanol synthesis. The reaction is mildly exothermic. A sulfur resistant catalyst is used in the shift conversion reactor. The gas leaving the shift reactor is then partially cooled by countercurrent exchange with the gas entering the reactor. Additional heat is extracted by generation of steam. Cooling water brings the shifted gas to 100°F. It is then blended with the bypass.

CO_2 Removal

A second Selexol plant is used to remove the bulk of the CO_2 contained in the synthesis gas before methanol synthesis. The second plant also removes residual H_2S and COS so that the total concentration of sulfur compounds is less than a tenth of a part per million (by volume). The CO_2 waste gas stream contains less than 100 parts per million H_2S and COS, and it can be vented without treatment.

Methanol Synthesis

The steps in the manufacture of methanol are described in the following paragraphs.

Methanol Reaction. The synthesis gas is converted to methanol in the methanol synthesis reactor, following reaction (1) by a process licensed by Imperial Chemical Industries Limited. This reaction is carried out at 1500 psi in a reactor containing a bed of metal oxide catalyst. The reaction is mildly exothermic.

Trace Sulfur Removal. Since the catalyst is degraded by sulfur compounds, a sulfur guard vessel consisting of a bed of zinc oxide removes trace quantities of sulfur compounds from the synthesis gas before it enters the reactor. The zinc sulfide formed is nonregenerable and must be replaced annually.

Product Gas Cooling. Gas leaving the reactor is cooled first by countercurrent exchange with the reactor feed gas, then in the boiler which generates 50 psig steam, and finally to $130^{\circ}F$ in a trim cooler using cooling water. This cooling step causes methanol to condense.

Gas Recycle. Reaction (1) does not go to completion. Therefore, the gases not condensing with the methanol are recycled to the inlet of the reactor. A small compressor raises gas pressure to inlet conditions of 1550 psia to be blended with incoming synthesis gas.

Purge Gas Separation. A small amount of methane is produced by a reaction competing with reaction (1):

$$3H_2 + CO = CH_4 + H_2O \qquad (3)$$

Much of this methane will condense with the methanol upon cooling. Also, some H_2 and CO will dissolve in the liquefied methanol at the high pressure of the reaction. When the liquid pressure is reduced to 50 psia, methane, H_2, and CO are revaporized and form a purge gas. The purge gas is separated from the liquid in a flash drum then mixed with the fuel gas.

Methyl Fuel Storage. Tankage is provided with capacity for storage of 4 million gallons of methyl fuel, a 6-months supply.

UTILITIES

Table 4-1 summarizes the utilities in the methyl fuel plant. The gasifier waste heat boiler generates enough steam to satisfy all process and heating steam requirements of the plant. However, the high-pressure steam from the waste heat boiler can provide only part of the requirements for mechanical power. The balance is to be made up by purchased electricity. The plant requires 94 gallons per minute of makeup water. Of this, 61 gallons per minute flow to the cooling tower to make up for evaporative, windage, and miscellaneous losses, and 33 gallons per minute flow to the boiler feed water treatment plant.

LAND REQUIREMENTS

Figure 4-2 presents a plot plan for the methyl fuel plant. It will occupy about 7.5 acres of land. In addition, the facility will include a 120 foot diameter methanol storage tank at some convenient location on the base.

OPERATING REQUIREMENTS

The following operating requirements will occur for a plant producing an average of 112.8×10^6 Btu/hr of methyl fuel and clean gas.

Materials

The materials required to operate the plant include the following:

Requirement	Quantity
Coal	58,800 short tons/yr
Electricity	28,145 megawatt – hours/yr

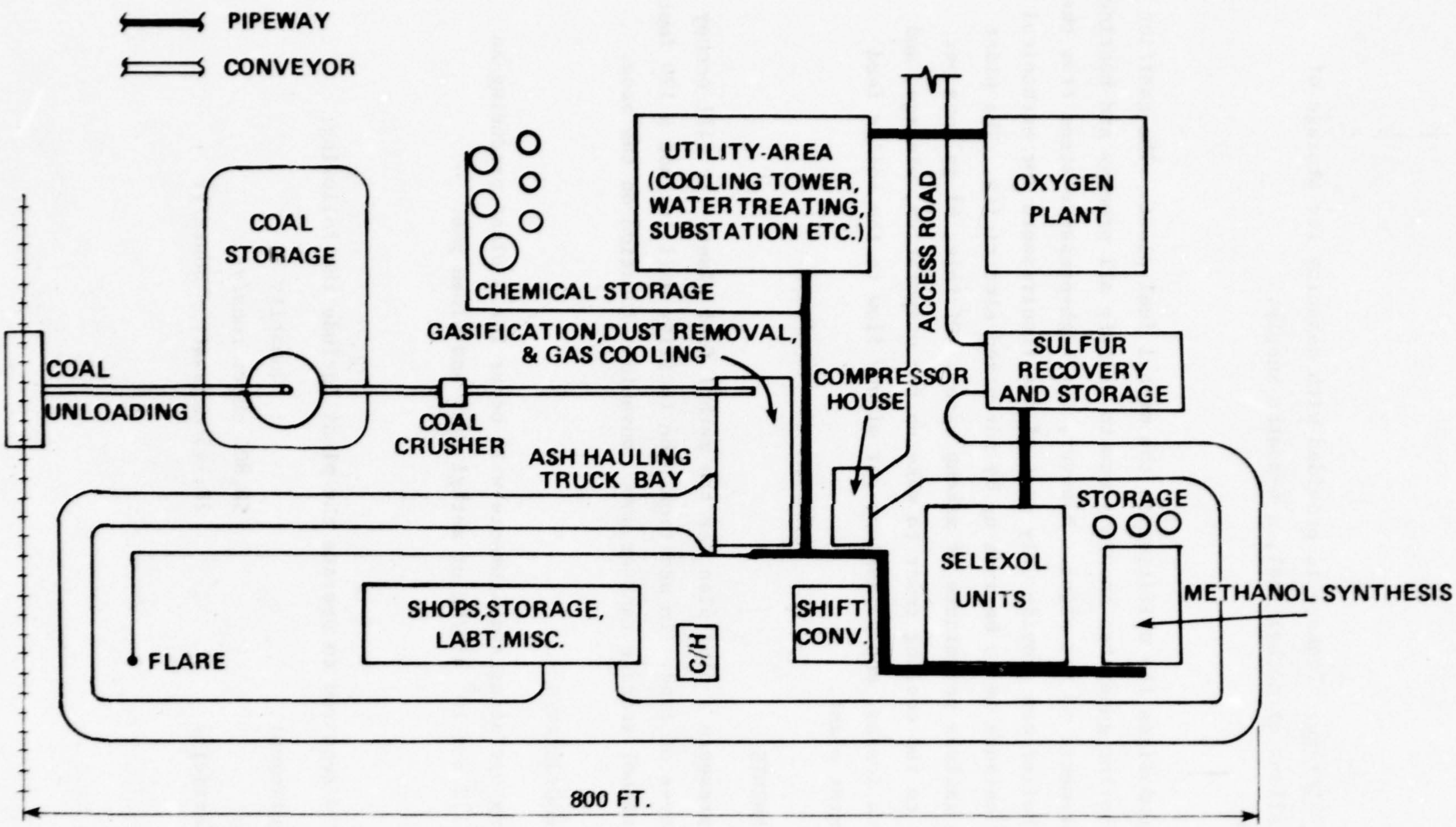


Figure 4-2 METHYL FUEL PLANT LAYOUT

	Electric Power	Fuel Gas	Cooling Water	Steam Produced 1500 psia 925^{o}F	1500 psia Saturated	165 psia Saturated
	Kilowatts	10^6 Btu/hr	gpm 25^{o}F ΔT	$10^3$16/hr	10^3 lb/hr	10^3 lb/hr
Coal Preparation	41.7	-	-	-	-	-
Oxygen Supply	590.4	-	110	-	-	-
Gasification and Gas Cooling	28.5	-	975	16,000	3,783	-
Gas Compression, Expansion	2,238.0	-	170	-	-	-
Desulfurization	373.1	-	530	-	-	-
Sulfur Recovery	7.1	0.5	-	-	-	914
Shift Conversion and Methanol Synthesis	309.6	-	275	-	-	1,807
CO_2 Removal	231.3	-	475	-	-	-
Utilities	82.2	-	-	-	-	(-2,721)
TOTAL	3901.9	0.5	2,535	16,000	3,783	-

* Noncondensing turbine exhaust, blended with condensate to form saturated steam

** Saturated 165 psia steam throttled to 65 psia steam, and blended with condensate to form saturated

Table 4-1

130×10^6 BTU/HR METHYL FUEL PLANT UTILITIES

	Steam Produced				Steam Condensed		
ing r	1500 psia 925°F	1500 psia Saturated	165 psia Saturated	65 psia Saturated	1500 psia 925°F	1500 psia Saturated	65 psia Saturated
a ΔT	$10^3$16/hr	10^3 lb/hr	10^3 lb/hr	10^3 lb/hr	10^3 lb/hr	10^3 lb/hr	10^3 lb/hr
	-	-	-	-	-	-	-
	-	-	-	16,248*	16,000	-	-
	16,000	3,783	-	-	-	-	14,123
	-	-	-	-	-	-	2,086
	-	-	-	-	-	-	4,865
	-	-	914	283	-	-	-
	-	-	1,807	7,260	-	3,783	-
	-	-	-	-	-	-	5,450
	-	-	(-2,721)	2,733**	-	-	-
	16,000	3,783	-	26,524	16,000	3,783	26,524

ate to form saturated steam

m, and blended with condensate to form saturated steam

J

In addition, there must be allowances for replacement of catalysts and chemicals; operating equipment, supplies and utilities; maintenance materials and subcontract labor; a waste disposal subcontract; and a fleet of five 5,000-gal tank trucks for home delivery service.

Labor

A 40-man work force is needed to operate the plant (8 men/shift, 5 shifts/week). Also, a four-man crew is needed during normal working hours to deliver liquid fuel to 4,000 individual dwellings.

Section 5

DIRECT COAL-FIRED STEAM PLANTS

As an alternative to gasification, bases can install new boiler plants to burn coal directly. These plants usually need pollution control equipment to meet sulfur and particulate air pollution control standards. This section presents a conceptual design of a coal-fired boiler facility which includes coal handling and scrubbing modules. The plant nominally consumes 250×10^6 Btu/hr of coal and produces 200,000 lb/hr of 150 psig steam. This nominal plant is the model for comparing direct-fired boilers with gasification plants. The plants required at individual bases are scaled up or down from this 250×10^6 Btu/hr model plant.

Figure 5-1 is an overall block diagram for the nominal plant. Table 5-1 provides details of component flows. The three main modules of the plant are described in the following paragraphs.

COAL PREPARATION

Approximately every 30 days coal arrives in a unit train with 100 bottom-dumping cars. The cars discharge the coal into an 800-ton receiving bin. A feeder and conveyance system under the receiving bin is sized to unload the train in six hours. The conveyance system transfers the coal to a 60-day live storage pile. Coal is reclaimed from live storage during one shift per day, crushed to -1/4 in. particle size, and conveyed to the day storage hoppers inside the boiler building.

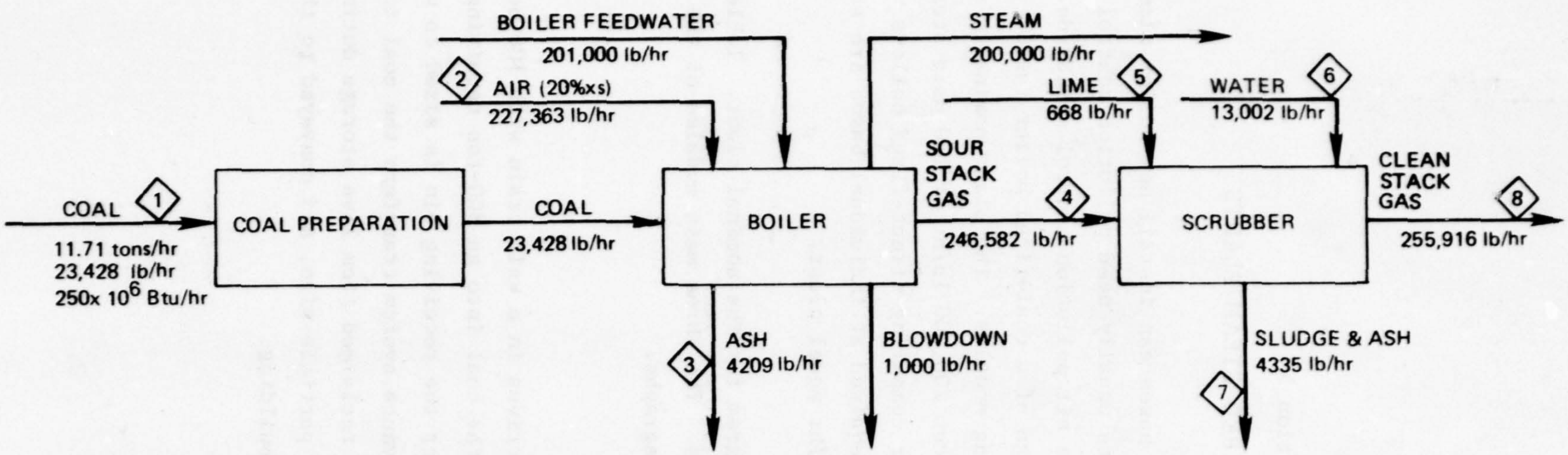


Figure 5-1

250x10^6 BTU/HR PULVERIZED COAL BOILER SYSTEM BLOCK DIAGRAM

Stream Number	1	2	3	4	5	6
Stream Name	Coal	Air	Ash	Sour Stack Gas	Lime	Wa
Temperature, ^{o}F	77.0	77.0		300.0		
Pressure, psia	14.7	14.7		14.7		
Moles/hr						
C	1,179.47		14.21	3.48		
H_2	429.97					
O_2	43.64	1,638.51		290.77		
N_2	11.79	6,163.94		6,175.73		
S	14.61					
Ash as SiO_2	83.68		67.22	16.46		
H_2O	65.02	125.50		620.48		7
SO_2				14.61		
CO_2				1,161.78		
CaO					11.91	
$CaSO_3 \cdot \frac{1}{2}H_2O$						
$CaSO_4 \cdot \frac{1}{2}H_2O$						
$CaCO_3$						
Total	1,827.95	7,927.95	81.43	8,283.31	11.91	7
Pounds/hr						
C	14,167		170	42		
H_2	867					
O_2	1,396	52,429		9,304		
N_2	330	172,673		173,003		
S	469					
Ash	5,028		4,039	989		
H_2O	1,171	2,261		11,178		13,0
SO_2				936		
CO_2				51,130		
CaO					668	
$CaSO_3 \cdot \frac{1}{2}H_2O$						
$CaSO_4 \cdot \frac{1}{2}H_2O$						
$CaCO_3$						
Total	23,428	227,363	4,209	246,582	668	13,0

1

Table 5-1

STREAM FLOWS IN 250 x 10^6 Btu/HR
PULVERIZED COAL BOILER SYSTEM

3 Ash	4 Sour Stack Gas	5 Lime	6 Water	7 Sludge	8 Clean Stack Gas
	300.0				
	14.7				
14.21	3.48			3.48	
	290.77				289.53
	6,175.73				6,175.73
67.22	16.46			16.46	—
	620.48		721.73	95.25	1,238.27
	14.61				4.68
	1,161.78				1,159.79
		11.91			
				7.45	
				2.48	
				1.99	
81.43	8,283.31	11.91	721.73	127.11	8,868.00
170	42			42	
	9,304				9,264
	173,003				173,003
4,039	989			989	
	11,178		13,002	1,716	22,307
	936				300
	51,130				51,042
		668			
				962	
				427	
				199	
4,209	246,582	668	13,002	4,335	255,916

2

BOILER

In the boiler building coal is pulverized and fired with 20 percent excess preheated air in a pulverized coal boiler that produces 150 psig saturated steam. Components in the boiler module include the following:

- Water softener
- Electrostatic precipitator removing at least 70 percent of the fly ash
- Forced draft fan
- Induced draft fan
- Boiler feed pump
- Deaerator
- Bottom ash and fly ash conveyors
- Stack

Boiler Efficiency

Boiler efficiency is defined as the heat transferred to make steam divided by the higher heat of combusion of the coal burned. The boiler in this nominal plant will be approximately 87 percent efficient. Losses will be as follows:

Efficiency Loss Mechanism	Percent Lost
Sensible heat in the flue gases	5.5
Latent heat in the flue gases	4.7
Unburned carbon in ash	1.2
Radiation and miscellaneous	1.6

SCRUBBER

Before entering the stack, the flue gases pass through a lime scrubber which removes SO_2 and the remaining fly ash.

Components

A stack gas scrubber contains the major components described below:

- An Absorber. Provides contact between flue gases and lime-bearing liquor so SO_2 in the flue gas can be absorbed. Lime-bearing liquor enters at the top of the vessel and leaves at the bottom. Gas enters at the bottom and leaves at the top.

- A Mist Eliminator. Usually located as the upper portion of the absorber vessel, removes entrained scrubbing liquor from the cleaned flue gases. Most of the makeup water is added here.

- An Effluent Hold Tank. Receives liquor leaving the bottom of the absorber. Makeup lime and some makeup water forming a slurry of slaked lime are added to the tank. Some of the tank's contents are recycled as fresh liquor to the absorber. The balance is bled away for clarification and filtration.

- A Clarifier. Permits initial settling of sludge solids that are contained in the bleed slurry. The supernatent liquid returns to the scrubber loop. Concentrated slurry is removed from the bottom.

- A Filter. Removes most of the water from the slurry leaving the clarifier. The water that is removed is returned to the scrubber loop. The filtered solids are called sludge.

SO_2 Removal Level

For comparisons, the scrubber is assumed to remove 70 percent of the SO_2 in the sour flue gas so that the cleaned flues contain 1.2 lb of SO_2 per million Btu of coal higher heating value. However, the scrubber is actually capable of removing over 90 percent of the entering SO_2.

Sludge

The SO_2 absorbed in the scrubber combines with dissolved lime and dissolved oxygen to form hydrated calcium compounds. Constituents of the sludge include the following:

- Calcium sulfite hemihydrate, $CaSO_3 \cdot .5H_2O$. This is the major sludge component formed. Since it is considered

a pollutant, the pond at the waste disposal site must be lined and runoff water must be collected and treated. This compound does not give good sludge consistency.

- Calcium sulfate dihydrate, $Ca\ SO_4 \cdot 2\ H_2O$. This compound is called gypsum. It is inert, and, therefore, it is nonpolluting. It improves the consistency of sludge, allowing it to be handled as a loose solid that can be stacked, rather than as a fluid. Experiments by scrubber vendors are indicating that it may be possible to convert all the sulfite to sulfate by sparging air through the sludge, before discharge. Sludge gypsum is a candidate raw material for making wallboard in Japan. In the United States, however, this use is not attracting much commercial attention yet.

- Calcium carbonate, $Ca\ CO_3$. Twenty percent excess lime is added to assure removal of the desired amount of SO_2. The excess lime usually combines with carbon dioxide from the flue gases.

- Fly ash. Scrubber vendors actually like some fly ash in the sour flues. This improves the solid consistency of the sludge.

- Water. The sludge cake produced by the filter contains 40 to 50 percent water. This level should be sufficiently low to assure good sludge consistency.

Cleaned Gas

The cleaned gas leaves the absorber at about 127^{o}F, saturated with water that was evaporated from the scrubbing fluid. The evaporation process cools the gas. The cleaned flues will have enough stack buoyancy without reheat. However, condensation of water and acidic gases will occur in the stack. Stack corrosion can be avoided by coating the inside surface of the stack with an impervious paint or coating.

WASTE DISPOSAL

The sludge and ash from the coal-fired boiler plant are conveyed to a temporary holding area, and then turned over to a contractor. The contractor is assumed to transport the solids and place them in a disposal pile 10 to

50 miles from the boiler. The disposal pile or "pond" is lined with clay or plastic. It has runoff control ditches and treatment ponds. The solids pond is periodically enlarged as the portions lined first are filled. Completely filled portions of the pond are finally covered with earth and revegetated.

UTILITIES

Table 5-2 tabulates the water and electricity requirements of the direct coal-fired boiler plant.

Table 5-2

UTILITIES FOR DIRECT COAL-FIRED BOILER PLANT

	Electricity Kilowatts	Water lb/hr
Coal preparation	75	—
Boiler	675	1,000
Scrubber	375	13,002
Miscellaneous	25	—
Total	1,150	14,002

PLANT LAYOUTS

Figure 5-2 provides a plot plan for a 250 million Btu/hr direct coal-fired plant. The facility will require 9 acres of land.

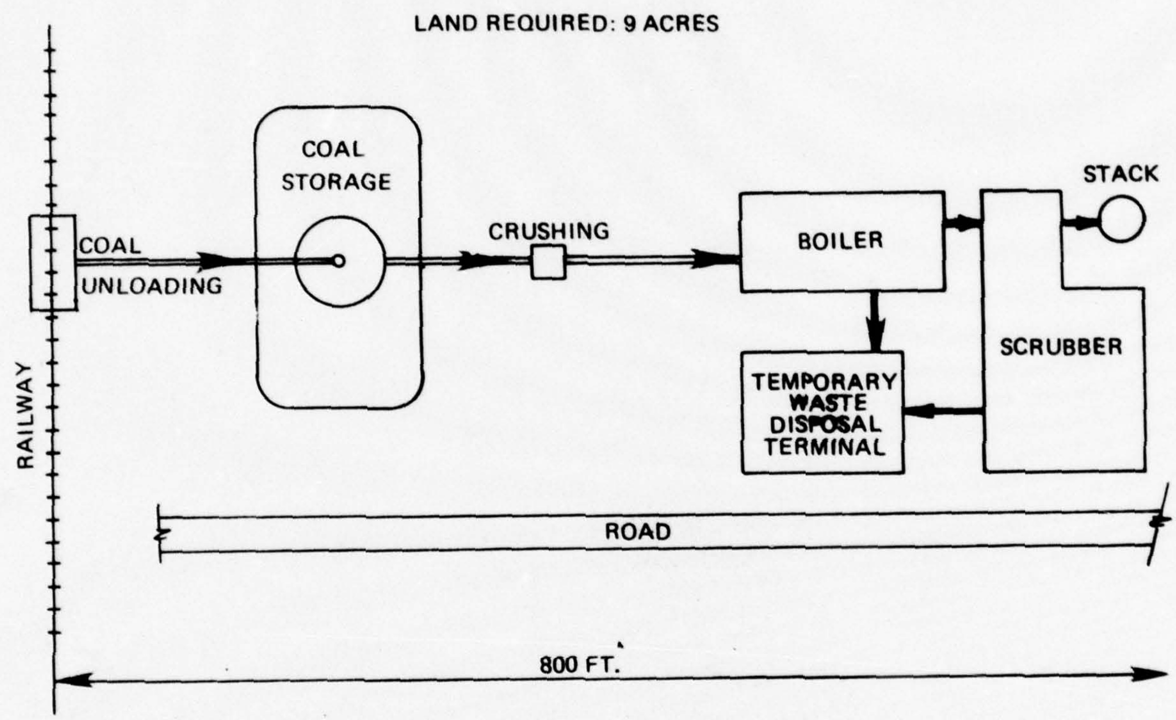


Figure 5-2 250 x 10^6 BTU/HR DIRECT FIRED COAL BOILER PLANT LAYOUT

Section 6

FACILITIES AT FIVE BASES

This section describes existing facilities and energy used at the five bases, and also sets forth the new facilities required for implementation of coal gasification and totally centralized new coal-fired boiler systems.

The information on existing facilities and energy use was obtained from the following sources:

- Visits by Bechtel personnel to the five bases
- Conversations with base public works engineers
- General development maps and detailed utility maps
- The FACSO system records on large steam generators and air heaters at each base
- The DEIS system records on energy consumption at bases
- Miscellaneous documents obtained during visits to bases

EXISTING FACILITIES

For the plants considered in this study, it is assumed that existing boilers can be used with a gasification option. Whether they can be used with the central direct coal-fired option is stated in the discussion.

CAMP PENDLETON MARINE CORPS BASE

Camp Pendleton Marine Corps Base is located on the Pacific Ocean approximately 50 miles north of San Diego. It extends inland about 11 miles and along the coast 18 miles. Elevations range from sea level to 1000 feet.

The base has residential, instructional, and industrial activities. Figure 6-1 is a plot plan.

Existing Boilers. The base has 396 boilers ranging in size from 600,000 to 24 x 10^6 Btu/hr with a total output of 650 x 10^6 Btu/hr. The boilers were installed over the period 1944 to 1972. Base engineers are planning to replace 67 boilers which were installed before 1955. The primary fuel for these boilers is natural gas. The backup fuel is oil. Many of the boilers serve industrial facilities and have an interruptible gas supply arrangement.

Residential Gas Consumption. Approximately 4,000 houses and mobile homes burn natural gas. Their total installed output is 280 x 10^6 Btu/hr.

Existing Gas Supply System. The base receives natural gas at several points along its boundary. Large transmission networks serve the Headquarters area and the strip from the San Onofre area to the Pulgas area.

Site for a Coal Gasification Plant or Central Coal-Fired Boiler Plant. An attractive site for a central coal facility lies between the hospital and the airstrip not far from the Headquarters area. The site is near a rail spur and existing gas transmission lines that serve 60 percent of the base heating load.

Usability of Existing Boilers for Central Direct Coal-Fired Boiler Plants. The boilers currently installed cannot burn coal. Consequently, none of the existing boilers could be used after conversion.

Facilities Served by New Coal Systems. For this study, Bechtel assumed that all industrial and residential loads on the base would be supplied either with medium Btu gas if a gasification plant is built, or steam if a central steam system is constructed.

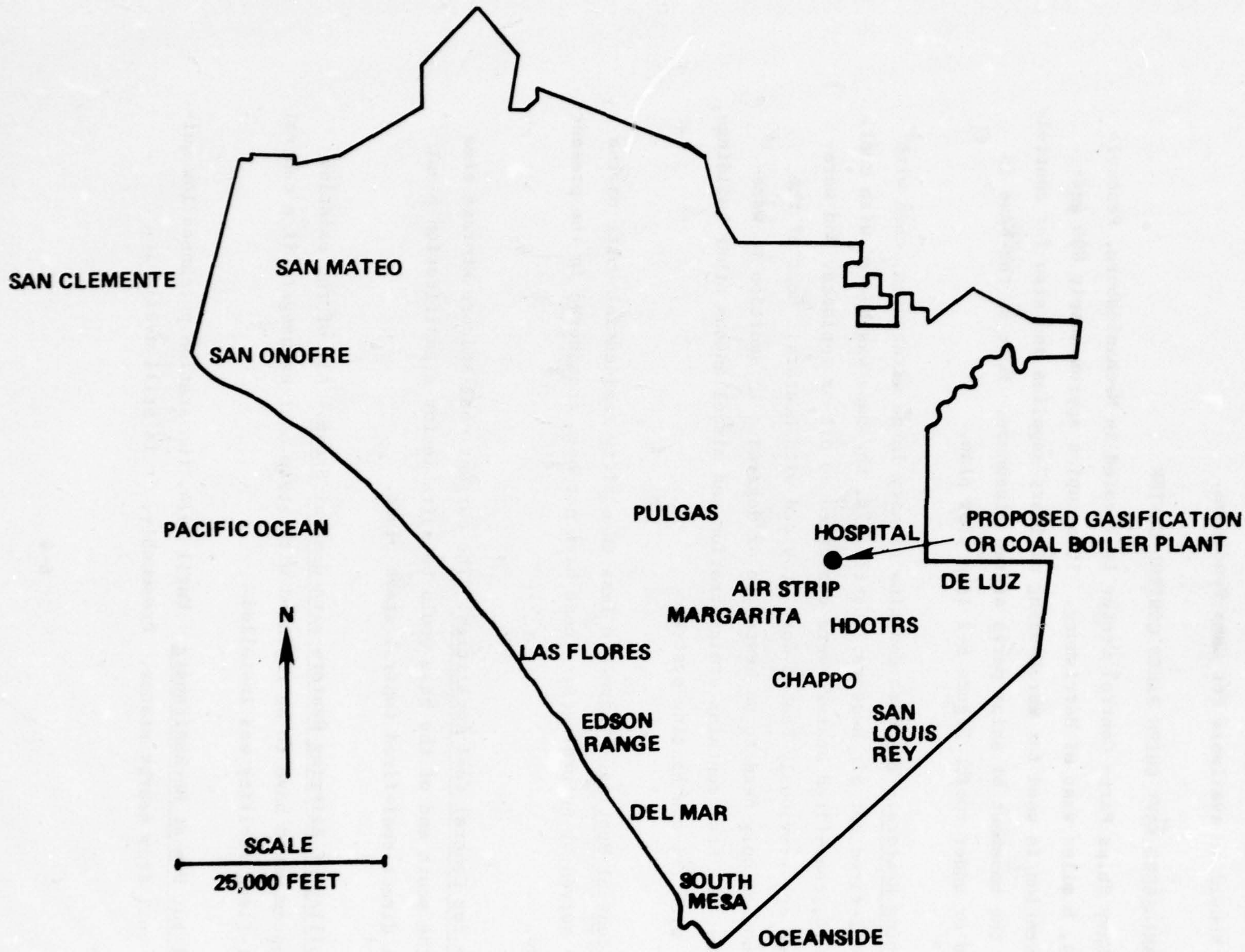


Figure 6-1 MARINE CORPS BASE, CAMP PENDLETON

Coal to be Used at Camp Pendleton. Coal from King Mine at Hiawatha, Utah containing .6 percent sulfur was purchased in 1977 by the Navy at $25.86/ton for facilities at Bremmerton, Washington, and Hawthorne, Nevada. A similar coal should be available for Camp Pendleton.

MECHANICSBURG NAVY SHIPS PARTS CONTROL CENTER

The Navy Ships Parts Control Center is located in Mechanicsburg, Pennsylvania, 6 miles west of Harrisburg. It occupies approximately 800 acres. The station is used for warehousing military supplies and also for controlling the movement of ships parts stored elsewhere. Most of the base is paved or under roof. Figure 6-2 is a plot plan.

Existing Heaters. The base contains seventy large warehouses, each with two oil-fired hot air heaters. Until 1974, the base was heated with coal. In 1974, coal-fired heaters were converted to oil or replaced, and warehouses not previously heated were provided with heaters. Most of the warehouses only need to be heated to 42 degrees. In addition to warehouses, the base contains administration and miscellaneous other buildings, each with its own heating system.

Residential Heating. There are less than fifty residential units on the base served by natural gas. These have not been considered in the present study.

Site for Central Coal Facilities. The current coal and ore storage area at the south end of the base would be suitable for a gasification plant or a direct coal-fired central steam plant.

Usability of Existing Heaters with Central Steam. All of the existing furnaces would have to be replaced with steam heat exchangers if a central coal-fired facility was installed.

Coal for Use at Mechanicsburg. Until 1974, the station purchased low sulfur coal from nearby states. Presumably, it is still available.

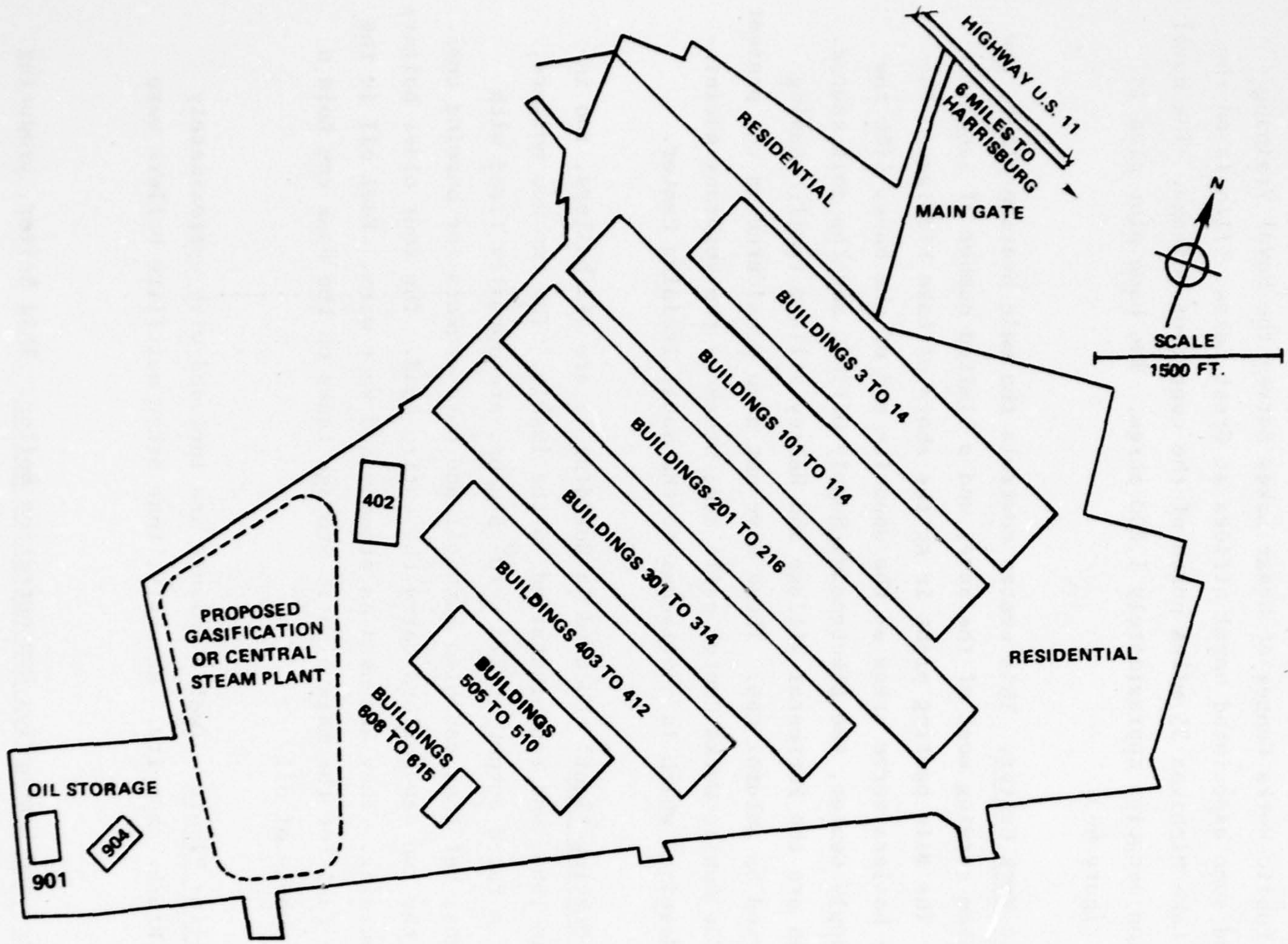


Figure 6-2 NAVY SHIPS PARTS CONTROL CENTER, MECHANICSBURG, PA

GREAT LAKES NAVAL COMPLEX

The Navy Public Works Center at Great Lakes serves the Naval Training Center and some associated naval offices at Great Lakes, Illinois on the shore of Lake Michigan 35 miles north of the center of Chicago. The naval reservation occupies approximately 1,200 acres. The base plot plan is shown in Figure 6-3.

The Public Work Center. This center controls the main heating plant, the steam system serving most of the base, and a limited number of satellite boilers. The main heating plant is at the shore of Lake Michigan. The satellite boilers serve areas at the opposite end of the base, like the N.T.C. Supply Center, the Electronics Supply Office, and the golf course. In between are the Forrestal Village and Halsey Village family housing areas served by natural gas. These have not been considered in the present study. The Public Works Center sells some steam to the Veterans Administration Hospital which is contiguous to the Naval Training Center.

The Main Heating Plant. Located in Building 11 are six boilers, two installed in 1965, and four installed in the 1940's. The two new boilers, each with a rated output of 273×10^6 Btu/hr, are normally fired with natural gas, but they can also burn oil and have stokers for burning coal. Normally the two new boilers carry the entire load. The four older boilers are oil burning. They are used as standby and kept warm. Fuel oil is the alternate fuel for the main plant. Storage tanks on the base can hold a two week supply of oil.

The Satellite Plants. Twelve boilers are included with approximately 81×10^6 Btu/hr capacity. Recently, four other satellite boilers were retired.

A Fluidized Bed Combustion Demonstration Boiler. This boiler, producing 50,000 lb/hr of steam is being constructed on the base. It will burn high sulfur Illinois coal.

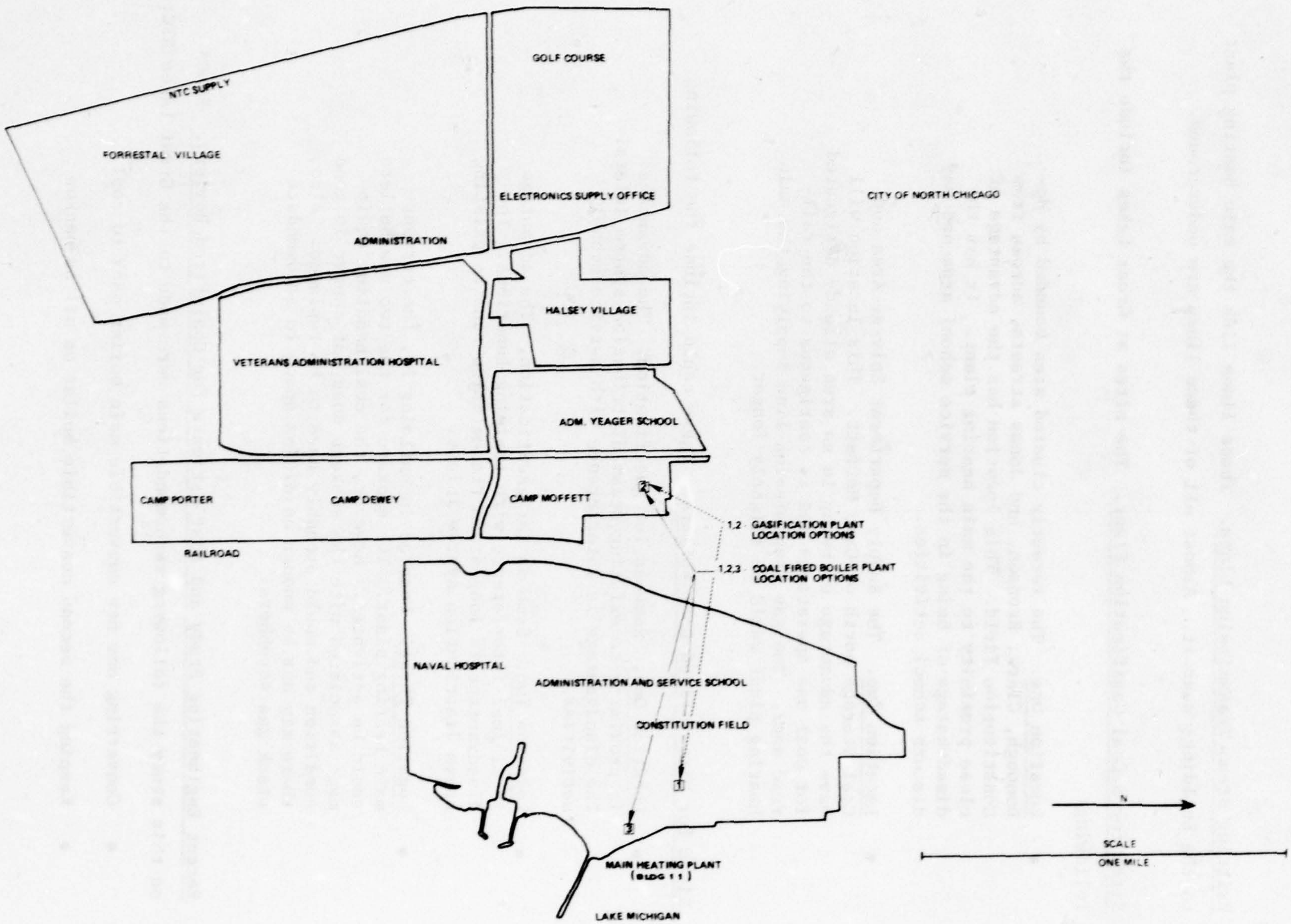


Figure 6-3 U. S. NAVAL TRAINING CENTER GREAT LAKES, ILLINOIS

Existing Steam Transmission Lines. These lines link the main heating plant to the buildings near it. Almost all of these lines are underground.

Sites for a Coal Gasification Plant. The sites at Great Lakes include the following:

- Location One. The recently cleared area bounded by Mc-Donough, Clark, Bronson, and Jones streets, across from Constitution Field. This location has the advantage of close proximity to the main heating plant. It has the disadvantage of being in the service school area and may disturb school activities.

- Location Two. The Supply Department Salvage Area and Coal Storage north of Camp Moffett. This location will have the advantage of being in an area already designated for coal use operations and is contiguous to the rail-road spur. The gas transmission line supplying the main heating plant would be slightly longer.

Sites for Direct-Fired Coal Boilers. These could include the following:

- Location One. Same as for gasification. The advantage is proximity to existing steam distribution system inlets. The disadvantage is interference with service school activities.

- Location Two. Same as for gasification. The advantage is minimal interference with training functions. The disadvantage is long steam transmission runs to existing steam distribution system inlets.

- Location Three. Located in Building 11, the current main heating plant. The stokers for the two new boilers could be activated. However, the coal handling equip-ment associated with the stokers does not appear in good condition and would probably have to be replaced. Also, there may not be enough adjoining space to accommodate stack gas scrubbers.

Recent Engineering Study and Cost Estimate for Coal-Fired Boilers. Based on this study the following recommendations were made to the Great Lakes NTC:

- Converting one new convertible main boiler back to coal

- Keeping the second convertible boiler on oil as backup

- Replacing the four old main boilers with two new stokers each generating approximately 190,000 lb/hr of steam

- Adding stack gas scrubbers

- Adding coal handling equipment

- Adding a $7,000,000 tunnel for coal conveyance

Bechtel Recommendations for Coal System Sites. For direct-fired coal plants, Bechtel recommends Location Three or Location One, or a combination. For gasification plants, Bechtel recommends Location Two.

Usability of Existing Boilers in Conversion to Coal. For this study, Bechtel has assumed that the existing new boilers will be used for backup, and new pulverized coal boilers with scrubbers will be installed to handle the main steam load.

Systems Served with New Coal Facilities. For this study, Bechtel has assumed that new coal facilities would serve the N.T.C. Supply area and the Electronics Supply and Golf Course area as well as the buildings now served by the main heating plant.

Coal to be Used at Great Lakes. A high sulfur Illinois coal will probably be used.

NORFOLK NAVAL COMPLEX

The Public Works Center serves the Sewells Point Area Naval Reservation in Norfolk, Virginia, where the Chesapeake Bay meets the Atlantic Ocean. The Sewells Point Area contains a naval base, a naval air station, a command headquarters and miscellaneous other naval activities. It occupies an area approximately 18,000 ft by 20,000 ft in the northwest corner of Norfolk. A plot plan is shown in Figure 6-4.

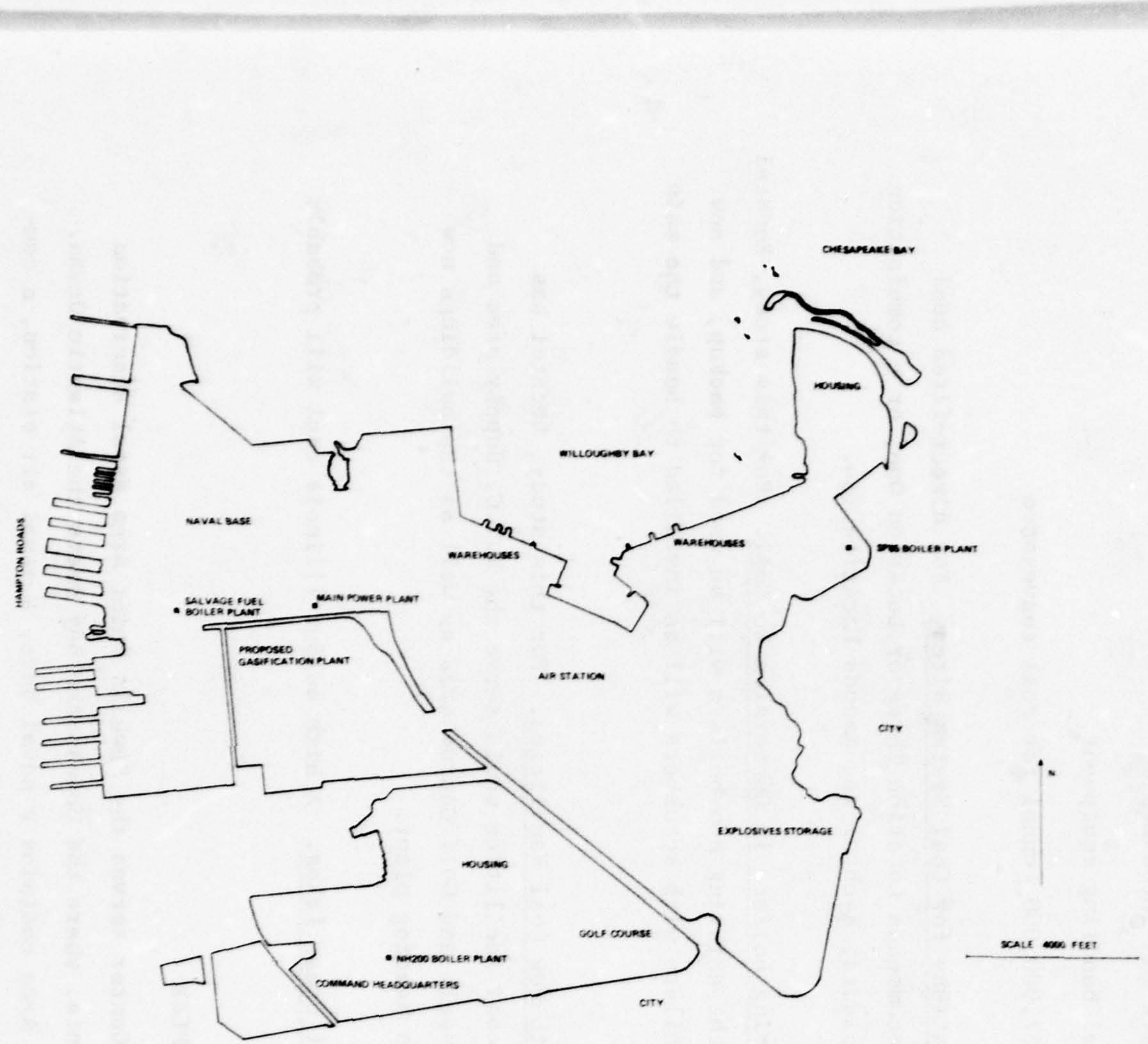


Figure 6-4 SEWELLS POINT AREA NORFOLK, VIRGINIA

The Public Works Center. This center controls the Central Power Plant and three satellite boiler plants. It also manages the natural gas use by residential housing units. Its steam is used for space heating of office, industrial, and warehouse buildings, for industrial shop processes, and also for space heating of ships docked at its piers.

The Central Power Plant. This plant currently contains six boilers built in 1941 having a total capacity of 565×10^6 Btu/hr. A new 200×10^6 Btu/hr coal-fired boiler is now being constructed. Four of the existing boilers (with output of 415×10^6 Btu/hr) have been burning oil for the last ten years, but they were originally designed for coal. The coal pulverizers, bunkers, handling equipment, and storage yard are in good condition and have been used weekly in anticipation of conversion back to coal. The associated electrostatic flue gas dust precipator is currently being overhauled.

Satellite Heating Plants. These plants include the following:

- Building SP85 contains two 75×10^6 Btu/hr boilers built in 1942 which can burn oil only.
- Building NH200 contains two oil-fired 75×10^6 Btu/hr boilers built in 1919. These are used only during peak load periods.
- The salvage fuel boiler plant contains two 54×10^6 Btu/hr boilers which burn refuse-derived fuel or fuel oil.

Existing Steam Transmission Lines. These lines include three major runs that connect the Central Power Plant with most of the nonresidential buildings on the base. Each of the major runs is also fed by a satellite plant.

Site for a Coal Gasification Plant. The area just south of the Central Power Plant is open land dedicated to railroad operations and outdoors storage. It has adequate space for a gasification plant. All construction at Sewells Point will require pilings.

Site for a New Direct Coal-Fired Plant. A new Central Power Plant could be built on the same site as proposed for the gasification plant, or the current plant building could be used. However, the current building may not be able to accommodate stack gas scrubbers.

A recent engineering study and cost estimate for conversion of the Central Power Plant back to coal recommended the following:

- Converting the coal convertible boilers to coal
- Adding an additional electrostatic precipitator
- Replacing the oil-only boilers with a new 212 x 10^6 Btu/hr coal-fired boiler plus an electrostatic precipitator
- Replacing and enlarging the coal off-loading and storage facilities

Bechtel's Assumptions on Boiler Usability. For this study, Bechtel has assumed that all major boilers except the salvage fuel boilers would be discarded or used only for backup in the direct coal-fired option, but would be retained and converted to gas in the gasification option.

Areas Served by New Coal Using Systems. All loads currently on the central steam system will be served. For this study, it was also assumed that individual housing units would be served from the same central steam plant.

Coal for Use at Norfolk. Coal from the Moss coal seam in Virginia's Grundy area 400 miles west would be available. It has 1.7 percent sulfur, and meets the 1.85 percent sulfur limit in local pollution standards.

QUANTICO MARINE CORPS BASE

The Marine Corps Base at Quantico, Virginia is approximately 35 miles south of Washington, D.C. on the Potomac River. It extends inland for 16 miles, and is 8 miles wide at its widest point. The part of the base that is settled and which requires heating is located in a 48 square mile area next to the Potomac River. This is shown in Figure 6-5.

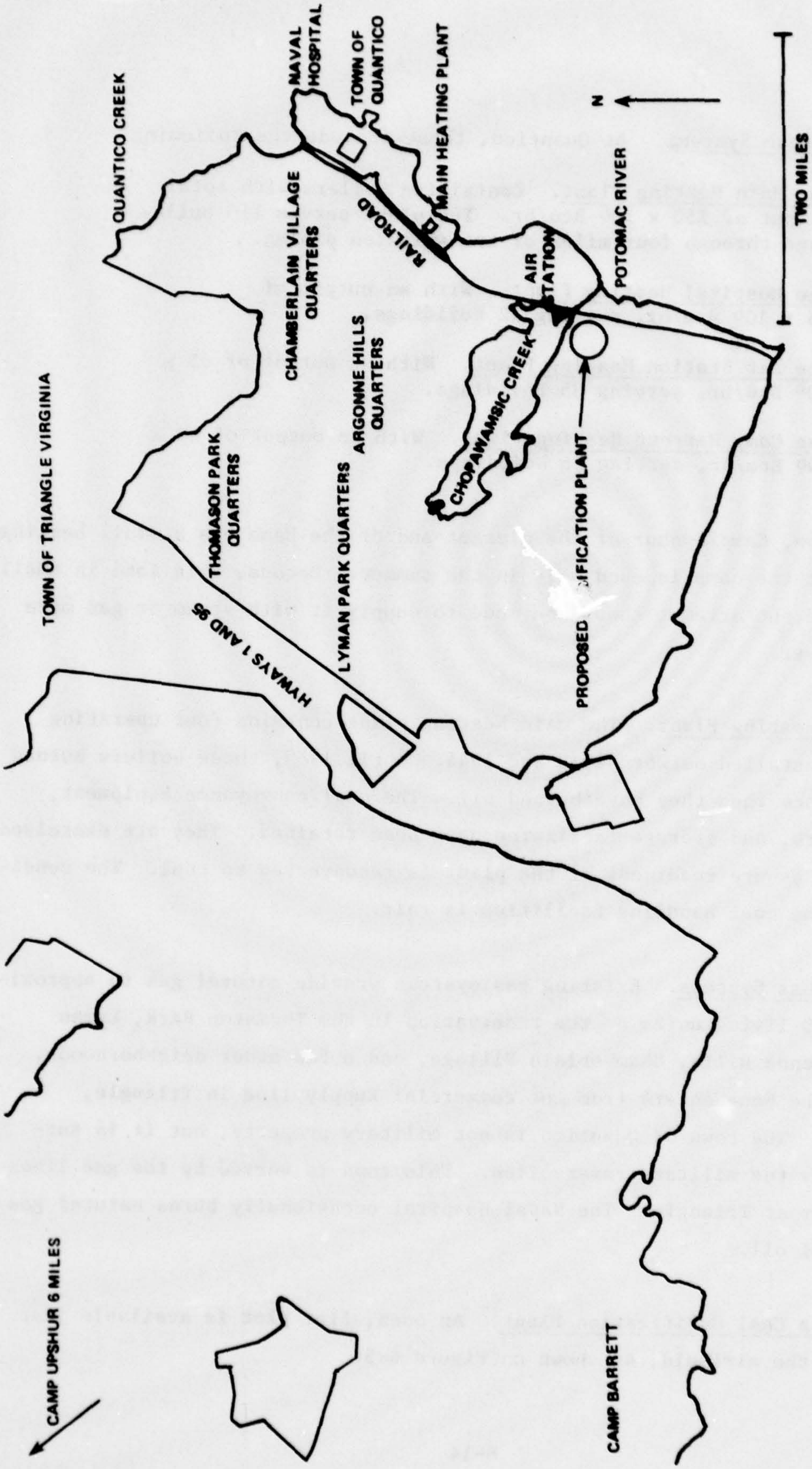


Figure 6-5 MARINE CORPS BASE, QUANTICO, VIRGINIA

Existing Steam Systems. At Quantico, these include the following

- The Main Heating Plant. Containing boilers with total output of 250 x 10^6 Btu/hr. The plant serves 110 buildings through four miles of transmission piping.

- The Hospital Heating Plant. With an output of 25 x 10^6 Btu/hr, serving 22 buildings.

- The Air Station Heating Plant. With an output of 65 x 10^6 Btu/hr, serving 35 buildings.

- The Camp Barrett Heating Plant. With an output of 40 x 10^6 Btu/hr, serving 36 buildings.

In addition, Camp Upshur at the distant end of the base has a small heating plant, but the camp is used only in the summer. Because this load is small and remote, no attempt should be made to supply it with steam or gas made at the river.

The Main Heating Plant. The main heating plant contains four operating boilers installed between 1938 and 1944. Until 1965, these boilers burned coal. Since then they have burned oil. The coal conveyance equipment, pulverizers, and storage facilities have been retained. They are exercised weekly to assure readiness if the plant is reconverted to coal. The condition of the coal handling facilities is fair.

Existing Gas Systems. Existing gas systems provide natural gas to approximately 900 living units on the reservation in the Thomason Park, Lyman Park, Argonne Hills, Chamberlain Village, and a few other neighborhoods. Gas for the base enters from the commercial supply line in Triangle, Virginia. The town of Quantico is not military property, but it is surrounded by the military reservation. This town is served by the gas lines that enter at Triangle. The Naval Hospital occasionally burns natural gas instead of oil.

Site for a Coal Gasification Plant. An open, flat plot is available just south of the airfield, as shown on Figure 6-5.

Site for New Direct-Fired Coal Facilities. For this study, Bechtel has assumed that new boilers would be installed in the current main heating plant.

Usability of Existing Main Boilers. Because of their age, Bechtel recommends discarding the existing main boilers and coal handling systems.

Areas Served by New Coal Systems. For this study, Bechtel has assumed that the coal gasification plant or new coal-fired boilers would serve all heating loads on the base, including residential, except those at Camp Upshur.

Coal Used at Quantico. In the past, the base obtained coal by rail from Island Creek Mine No. 22, 300 miles away in West Virginia. It is presumably available. The coal usually had a sulfur level of .6 percent. A typical sample was received with 3 percent moisture, 12.3 percent ash, and a heating value of 12,730 Btu/lb.

METHODS FOR SIZING NEW COAL FACILITIES

Two possible approaches could be followed in determining the size of new facilities to implement coal utilization:

- The installed capacity method
- The consumption and weather data method

These are discussed below.

Installed Capacity Method. In this method, the capacity of the new facility is equal to the total installed capacity of the existing facilities replaced or served. The total capacity at each of the five bases is shown in Table 6-1. This method exaggerates the peak demand, because the complement of large furnaces at the bases is known to have substantial excess installed heating capacity (through boiler over design and retention of old boilers as spares). This method was not used in this study.

Table 6-1

TOTAL INSTALLED CAPACITY OF EXISTING HEATERS AND BOILERS

Base	Capacity 10^6 Btu/hr Based on Output*	Based on Fuel Used*
Camp Pendleton	905	1130
Mechanicsburg	375	470
Great Lakes	544	680
Norfolk	1175	1465
Quantico	510	640

*Capacity based on output (or heat transferred) is .8 times capacity based on fuel used.

Consumption and Weather Data Method

In this method, the average current hourly consumption is used along with weather data to determine a design capacity. From the weather data, it is possible to compute the ratio of the peak heating demand to the average heating demand during the coldest month. This allows computing peak heating demand from average consumption during the coldest month. This method was considered more reliable than the installed capacity method, and was used to compute capacities for the new gasification and direct-fired coal plants. Details are provided in the next section.

AVERAGE AND PEAK FUEL DEMANDS

Table 6-2 presents average and peak energy consumption rates at the five military installation. The methods of obtaining the entries in the table and some inferences about plant sizes are discussed in the following paragraphs.

Annual and Peak Month Fuel Consumption

Monthly consumption of oil and natural gas in Fiscal Year 1976 was obtained from Defense Energy Information System (DEIS) reports for Mechanicsburg, Great Lakes, and Norfolk. Comparable information was obtained from base records during trips to Camp Pendleton and Quantico. The monthly data were used to compute an annual average consumption rate. The annual average governs the annual cost of energy for the base. The consumption rate of the month with the highest average is also listed for each base. This was used to compute peak demands as explained in the next paragraphs.

Table 6-2

AVERAGE AND PEAK FUEL DEMANDS
(Millions of Btu/hr)

	Pendleton	Mechanics-burg	Great Lakes	Norfolk	Quantico
Annual Average	103	43	102	269	158
Peak Month Average	170	130	200	460	286
Peak Day Average	320	308	380	750	458
Peak 4-Hour Period	450	325	415	840	536

Peak Day Fuel Consumption

Temperature occurrence frequencies were estimated using Air Force-Navy engineering weather data for locations at or near the five bases. The following procedure was used to calculate the maximum system capacity that should be installed and is amplified in Appendix D:

1. For calculation purposes, all the heat used at the bases was assumed to be for space heating.

2. January 97.5 percent temperatures* indicated in Table 6-3 as "coldest day" temperatures were selected for design. The peak day of Table 6-2 was at this design temperature.

3. Degrees and degree-hours of heating were computed assuming the distribution of loads shown in Table 6-4.

4. The ratio between the degrees of heating at the design temperature and the average degrees of heating during the coldest month was computed.

5. The capacity required to meet the heating needs at the design temperature was assumed to be the coldest month average fuel consumption times the ratio from (4) above.

Peak Four-Hour Period Demand

At each base, the fuel demand will be higher during the period between 5 a.m. and 9 a.m. than during the remainder of the coldest day. Table 6-2 shows the predicted demand during the peak 4-hour period. At Camp Pendleton, the peak 4-hour demanc is substantially higher than the peak day average demand.

Housing vs Industrial Loads at Camp Pendleton for Sizing Methyl Fuel Plant

Monthly natural gas consumption measured at 25 metering points at Camp Pendleton was used to determine the split between housing loads and industrial loads. This split was needed for sizing a methyl fuel plant. The annual average domestic consumption was 41×10^6 Btu/hr. The average industrial consumption was 62×10^6 Btu/hr.

SIZES OF NEW FACILITIES

Gasification plants and direct coal-fired boiler plants were sized for each base. Also, a methyl fuel plant was sized for Camp Pendleton. Each

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* The temperature is equal to or greater than this temperature 97.5 percent of the time during January.

Table 6-3

COLDEST DAY TEMPERATURES FOR HEATING SYSTEM DESIGN

Base	Coldest Day Temperature, ^{o}F
Camp Pendleton	34
Mechanicsburg	7
Great Lakes	-1
Norfolk	23
Quantico	15

Table 6-4

DISTRIBUTION OF HEATING LOADS

Type of Load	Fraction of Base Heating Capacity		
	Domestic & Equivalent (1)	Classrooms, Work Spaces (2)	Cold Warehouses (3)
Camp Pendleton	.5	.5	—
Mechanicsburg	.2	—	.8
Great Lakes	.5	.5	—
Norfolk	.7	.3	—
Quantico	.6	.4	—

Load Explanations:

(1) Domestic, 24 hour offices, and "cold iron" loads are kept continuously at $70^{o}F$, or above.

(2) Classrooms and workspaces that are used 8 hours/day are allowed to drop $50^{o}F$ during the night, and are heated back to $70^{o}F$ just before day shift use begins.

(3) Warehouses at Mechanicsburg require heating when the ambient temperature drops below $42^{o}F$.

facility consists of a central plant, plus transmission and distribution piping, and retrofit equipment at the actual loads.

Gasification Plants

Table 6-5 presents the gasification plant sizes selected for each base. The following considerations led to the entries shown in the table:

- Size Criterion. In each case, the total capacity satisfies the peak day average demand. Future conservation efforts are expected to more than offset any base expansion.

- Gas Storage. To satisfy the peak four-hour period on the peak day at Camp Pendleton, a gas storage sphere is provided. The sphere can discharge 130 x 10^6 Btu/hr for eight hours. The 130 x 10^6 is the difference between Camp Pendleton's peak four-hour demand and their peak day average demand. Storage was not deemed necessary at the other bases.

- Multiple Trains. At Mechanicsburg and Great Lakes, all loads served by a new gasification system are able to burn fuel oil as a backup fuel in case the gasification plant should suffer an unscheduled outage. Accordingly, only one train of gasification has been specified for these two bases. At Camp Pendleton, 40 percent of the consumption is by domestic space heaters which cannot use oil as a backup. Therefore, two half-capacity trains are needed at Camp Pendleton. For Norfolk and Quantico, only a single train of gasification has been included for calculation purposes in this study, even though two would actually be needed to assure service to the housing. This was done to show that even under the most optimistic assumptions, gasification does not appear competitive at these two bases.

Direct Coal-Fired Boiler Plants

Table 6-6 presents sizes for boiler plants at the bases. Factors leading to the entries in the table are as follows:

- Size Criterion. At Camp Pendleton, the peak four-hour demand was selected as the size criterion. At the other bases, the peak day average consumption was deemed adequate.

Table 6-5

GASIFICATION PLANT CAPACITIES

Base	Maximum Product Gas Manufacture Rate 10^6 Btu/hr	Number of Process Trains*	Gas Storage, 10^6 Btu
Camp Pendleton	320	2	1040
Mechanicsburg	308	1	0
Great Lakes	380	1	0
Norfolk	750	1	0
Quantico	458	1	0

* Process trains include all modules except solids handling.

Table 6-6

NEW DIRECT COAL-FIRED BOILER PLANT CAPACITIES

Base	Maximum Coal Consumption Rate 10^6 Btu/hr	Number of Trains**	Annual Average Fuel 10^6 Btu/hr
Camp Pendleton	500	2	135.3
Mechanicsburg	313	2	43.4
Great Lakes	388	2	102.0
Norfolk	762	2	269.0
Quantico	488	2	166.0

* Assume 100 x 10^6 Btu/hr of coal produces 80,000 lb/hr of steam.

** Boilers and Scrubbers are multiple; coal and ash handling are single train.

- Thermal Losses. At Camp Pendleton, substantial thermal losses from steam pipes are predicted, since the central design leads to several extremely long pipe runs. These losses lead to a higher required maximum boiler capacity, and also to a higher average annual fuel consumption rate.
- Multiple Trains. Since boiler turndown ratios are about one-third, and expected fluctuations in demand may be in the ratio of 1 to 6, two trains have been provided for each base.

Transmission Lines

New plastic pipes for gas transmission and insulated steel and condensate return pipes for steam transmission have been specified for the five bases. Both types of pipe are assumed buried in trenches or conduits. The new gas and steam lines needed at each base are shown in Figures 6-6 to 6-10. Camp Pendleton pipe runs were designed for a 100 psi pressure drop, assuming flows proportional to installed load capacity. Pipe diameters at other bases were estimated by ratio from Camp Pendleton pipes. Table 6-7 summarizes the total length of transmission lines at the bases.

Table 6-7

TOTAL LENGTHS OF NEW TRANSMISSION PIPE AT THE FIVE BASES

Base	Length, Miles	
	Gasification Plant	Direct Load Fired Boiler Plant
Camp Pendleton	33	57
Mechanicsburg	3	3
Great Lakes	3	3
Norfolk	6	5
Quantico	14	21

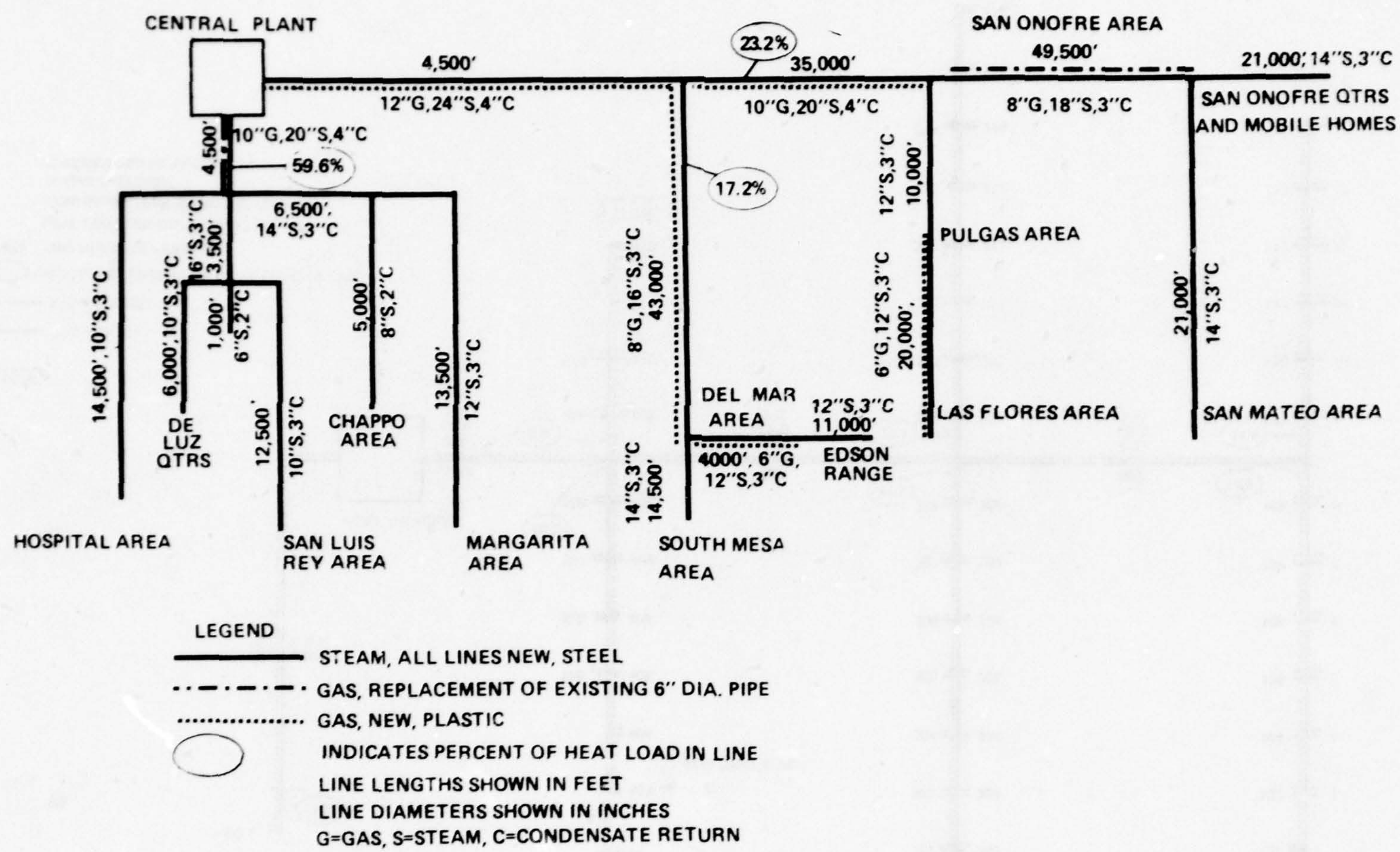


Figure 6-6 MARINE CORPS BASE, CAMP PENDLETON, NEW TRANSMISSION LINE SCHEMATIC

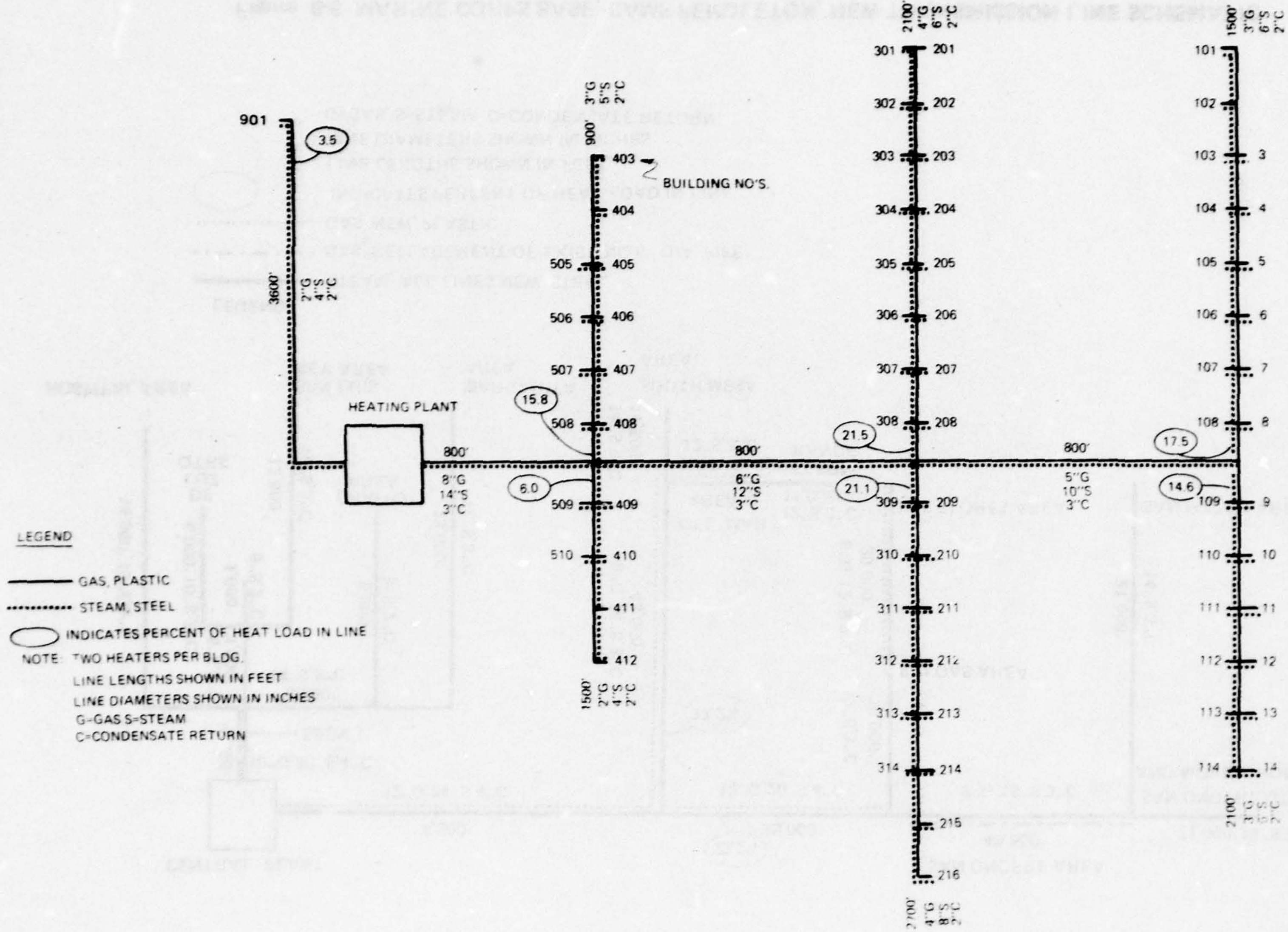


Figure 6-7 SPCC, MECHANICSBURG, NEW TRANSMISSION LINE SCHEMATIC

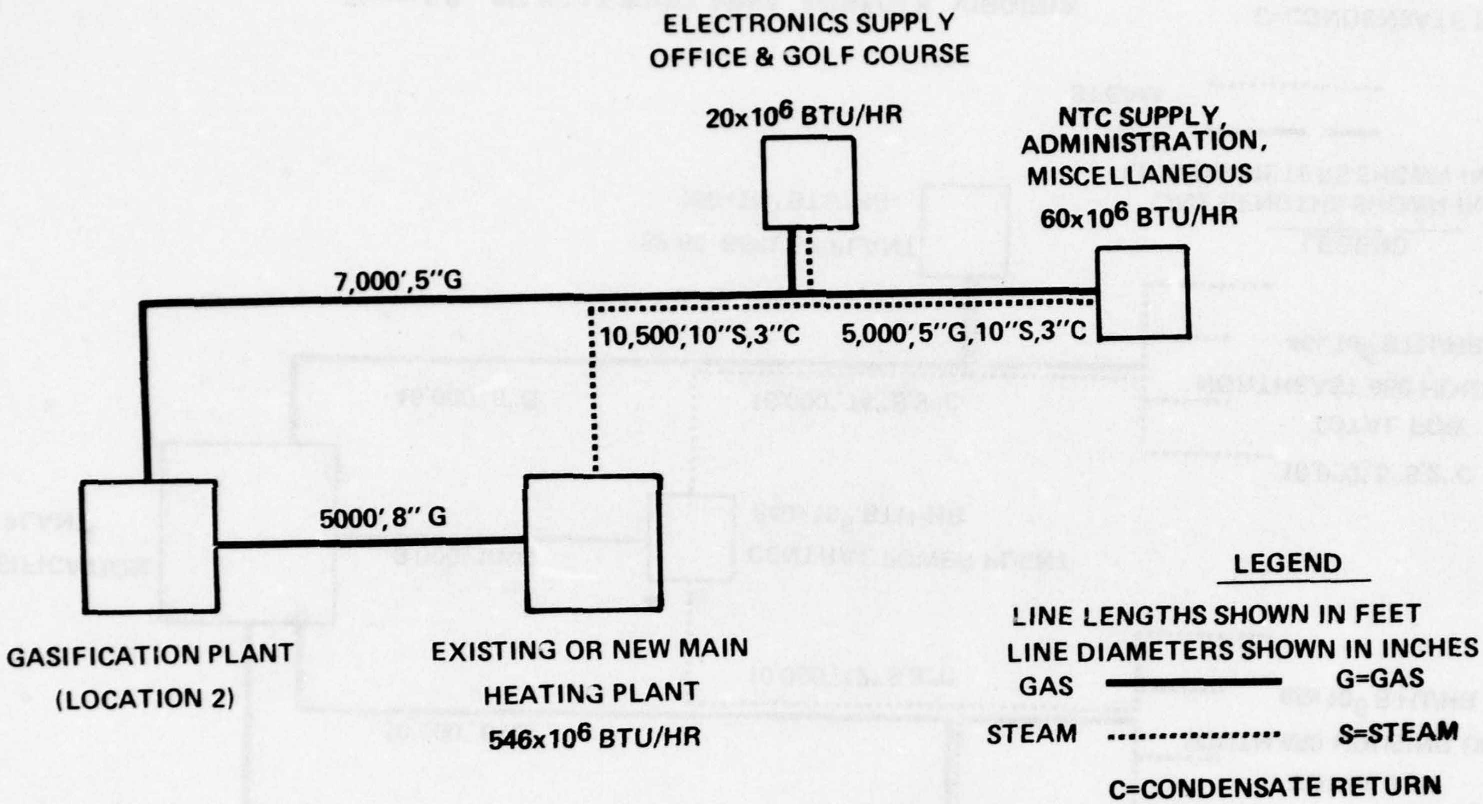


Figure 6-8 PUBLIC WORKS CENTER, GREAT LAKES NAVAL TRAINING CENTER, NEW TRANSMISSION LINE SCHEMATIC

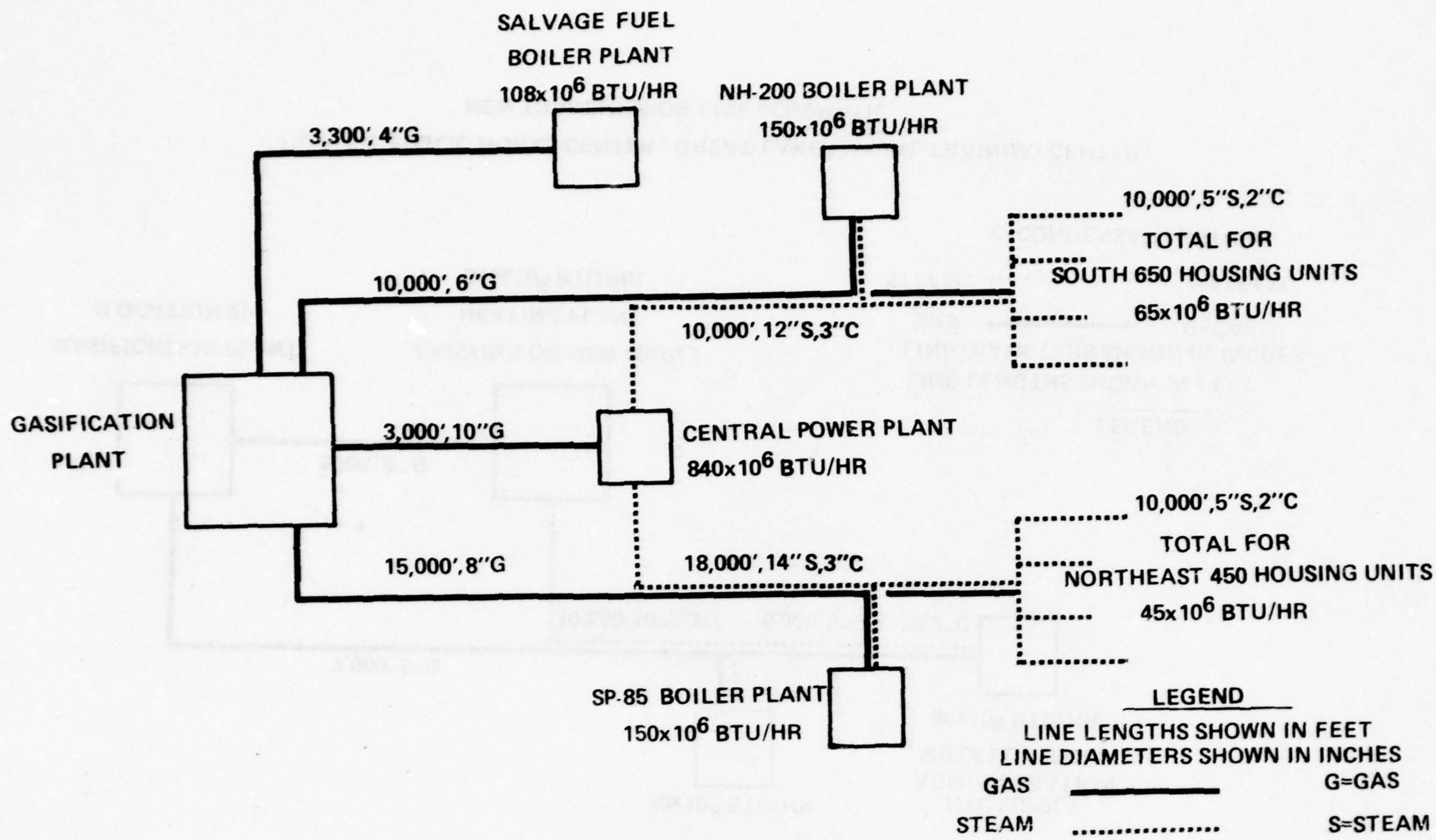
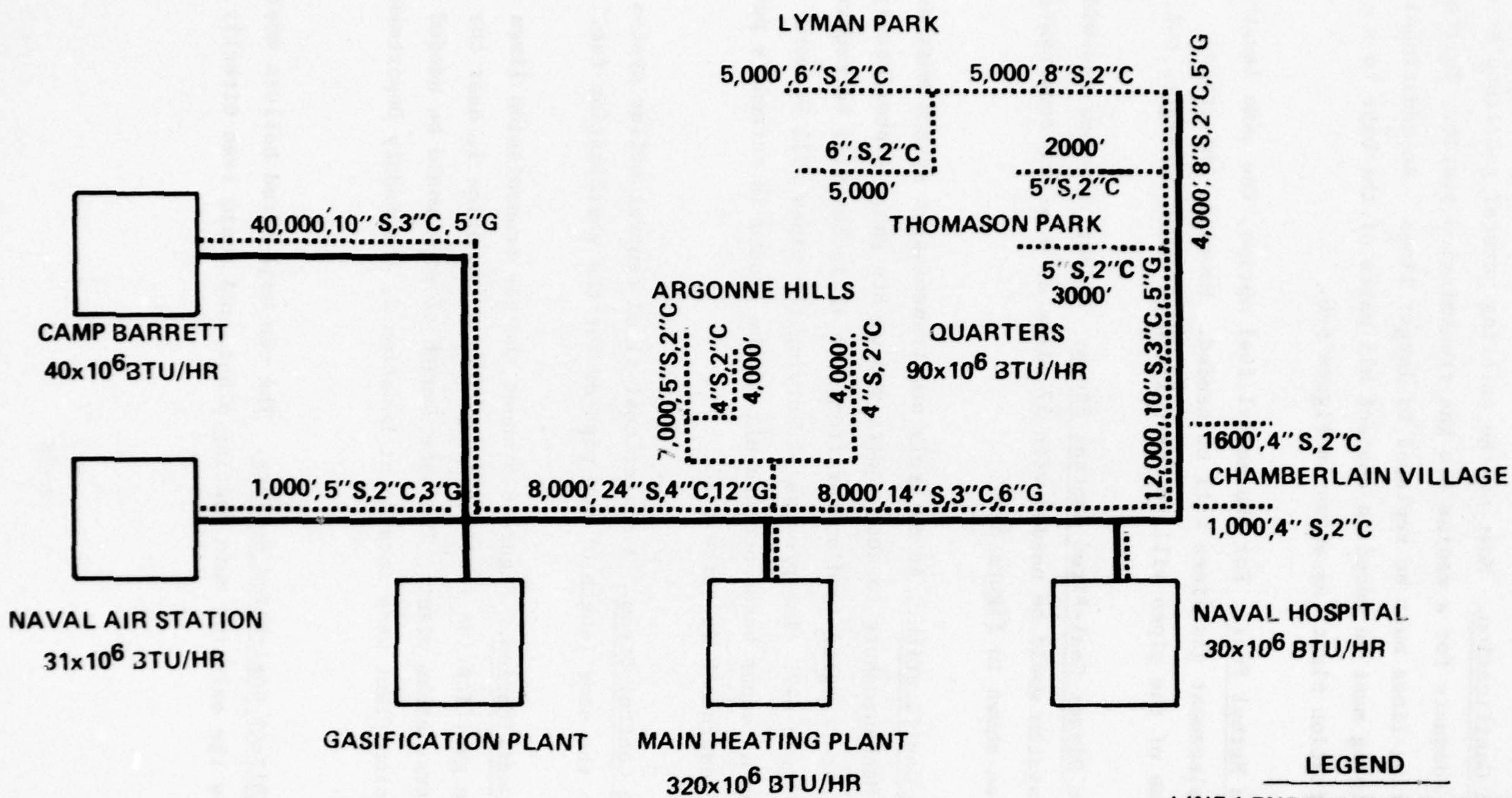


Figure 6-9 SEWELLS POINT AREA, NORFOLK, VIRGINIA
NEW TRANSMISSION LINE SCHEMATIC



LEGEND

LINE LENGTHS SHOWN IN FEET

LINE DIAMETERS SHOWN IN INCHES

GAS ——— G=GAS

STEAM .... S=STEAM

C=CONDENSATE RETURN

Figure 6-10 MARINE CORPS BASE, QUANTICO, NEW TRANSMISSION LINE

Camp Pendleton Gasification. Most of the existing natural gas lines at Camp Pendleton are adequate for a medium Btu gas transmission system. Thirteen miles of existing lines must be replaced by larger lines. An additional 22 miles of piping must be added to connect all parts of the base to a central gasification plant, as shown in Figure 6-6.

Camp Pendleton Methyl Fuel. For the methyl fuel option, the same length of new and replacement gas lines will be needed. However, the cross-sectional areas of the pipes will be one-half those shown in Figure 6-6.

Camp Pendleton Direct Coal-Fired Central Steam. An entirely new basewide transmission system would be needed with 57 miles of pipe and condensate return lines as shown in Figure 6-6.

Mechanicsburg Gasification. An entirely new transmission system must be installed at Mechanicsburg to accommodate medium Btu gas. Approximately 3.2 miles of pipe ranging in diameter from 4 to 12 inches will be required, as shown in Figure 6-7. The process of burying the pipes will be more difficult than at other bases because all of the ground is currently paved and the clay underneath is quite hard.

Mechanicsburg Central Steam. A direct coal-fired central boiler system would require the same length of new pipe as for the gasification facility.

Great Lakes Gasification. Figure 6-8 shows the gas transmission lines needed if the gasification facility is located at Location 1, near the existing central steam plant. The same length of pipe would be needed if the gasification plant were located at Location 2, the Supply Department Salvage area.

Great Lakes Direct Coal-Fired Boilers. The new coal-fired boilers would be located by the existing main heating plant, and would feed directly

into the existing steam transmission network. However, new lines would be installed to supply the N.T.C. supply area and the Electronics Supply and Golf Course.

Norfolk Gasification. Tranmission lines to the Central Power Plant and the three satellite boilers will be provided. Also, lines to the two housing areas will be needed. Inside the housing areas, existing natural gas transmission lines will be used.

Norfolk Direct Coal Firing. New express transmission lines to Buildings SP 85 and NH 200 would be added. These will assure adequate peak flow in the absence of the discarded satellite boilers in these areas. These two transmission lines will also be extended into the two housing areas.

Quantico Gasification. Transmission lines to each of the existing major heating plants would be provided. These plants include the main heating plant, the air station plant, the hospital plant, and the Camp Barrett plant. Also, a line would be provided to the inlet of the existing natural gas line serving residential housing units. This inlet is next to the town of Triangle, Virginia.

Quantico Direct Coal Firing. New transmission lines would be added to connect the main heating plant to the existing steam systems at the air station, the hospital, and Camp Barrett. Also, transmission to the quarters areas are provided.

Distribution Lines

Smaller lines connecting the transmission lines to actual individual heat loads are called distribution lines in this study. At Camp Pendleton, Norfolk, and Quantico the significant distribution lines serve the residential housing units. At Mechanicsburg, the significant distribution lines serve

the warehouse furnaces. At Great Lakes, no distribution lines have been provided, since only major heating plants are served. Each distribution line was assumed to be buried and between 75 and 150 feet in length.

Retrofit

Some modifications may be required in burner and heat exchange equipment when loads are switched to medium Btu gas or steam. The following retrofit modifications have been included in the cost estimates in Section 7.

Dwellings Switched to Medium Btu Gas. These will require a new burner and ignition system to replace the current natural gas burners because medium Btu gas has different flashback and flame velocity characteristics. Also, for kitchen safety, gas ranges must be replaced by electric ranges.

Dwellings Switched to Central Steam. These will require a steam-air heat exchanger to replace natural gas-fired air heaters. Also, gas-fired kitchen ranges and water heaters are assumed to be replaced by electric ones.

Large Oil Burners Switched to Medium Btu Gas. These will require new burner and ignition systems.

Large Air Heaters Switched to Central Steam. These will require replacement by steam-air heat exchangers and forced draft fans.

Local Steam Networks Switched to Central Steam. These will require no retrofit equipment. Steam from the central plant will be fed directly into the outlet of the local steam generator.

Table 6-8 summarizes the number of heat loads requiring retrofit at the bases.

Table 6-8

HEAT LOADS REQUIRING RETROFIT

Base	Number of Dwellings	Number of Large Local Boilers	Number of Large Local Air Heaters	Number of Buildings With Large Boilers or Heaters
Camp Pendleton	4,000	396	—	326
Mechanicsburg	0	—	146	73
Great Lakes	0	18	—	3
Norfolk	1,100	12	—	4
Quantico	900	25	—	13

Methyl Fuel Plant at Camp Pendleton

Section 4 of this report describes a methyl fuel plant sized to the needs of Camp Pendleton. The transmission lines for medium Btu gas at Pendleton would have diameters half those shown in Figure 6-6, and would serve only industrial areas. Retrofits to dwellings priced in Section 7 include:

- A methyl fuel vaporizer and burner to insert in existing heaters
- A 250 gal volatile liquid storage tank buried near the sidewalk with feed lines to each house
- Electric ranges and water heaters

Section 7

ECONOMICS

In this section, capital costs, annual operating costs, and present values are computed for coal gasification plants, a methyl fuel plant, and direct coal-fired boilers and scrubbers at the five bases.

For reference, costs are also presented for a "status quo," continued use of fuel oil in existing equipment with no new capital investment.

CAPITAL COSTS

Capital costs for Camp Pendleton are shown in Table 7-1 for a coal gasification system; Table 7-2 for a methyl fuel plant; and Table 7-3 for a direct coal-fired boiler system with scrubber.

Table 7-4 presents the total capital costs for all five bases for the systems studied. Detailed modular breakdowns for the four other bases are shown in Table E-1 and E-2 of Appendix E.

The comparison in Table 7-4 shows that coal gasification will involve lower capital costs than the direct coal-fired boiler alternative only at Camp Pendleton.

OPERATING COSTS

Table 7-5 presents annual operating costs for all three systems studied for Camp Pendleton.

Table 7-1

CAPITAL COSTS OF MEDIUM BTU
GASIFICATION PLANT FOR CAMP PENDLETON

(Fourth Quarter 1977 Dollars)

Two 160 x 10^6 Btu/hr Process Trains, with Gas Storage	Cost Thousands of Dollars
Coal Receiving and Preparation	4,500
Oxygen Supply	10,200
Gasification and Gas Cooling	13,100
Raw Gas Compression	3,100
Desulfurization and Dehydration	2,200
Sulfur Recovery and Tailgas Treatment	2,900
Interconnecting Piping	2,100
Utilities	1,000
Waste Disposal Terminal	600
Gas Storage	4,000
Gas Transmission	6,700
Gas Distribution	200
Retrofit Equipment	2,800
Total Direct Cost	53,400
Distributables	3,800
Total Field Cost	57,200
Engineering and Fee	6,300
Total Construction Cost	63,500
Startup Costs	7,000
Total Capital Costs	70,500

Table 7-2

CAPITAL COSTS OF A PLANT PRODUCING
METHYL FUEL AND MEDIUM BTU GAS FOR CAMP PENDLETON
(Fourth Quarter 1977)

One Train, 140×10^6 Btu/hr Gas, 62×10^6 Btu/hr Methyl Fuel	Cost Thousands of Dollars
Coal Receiving and Preparation	3,600
Oxygen Supply	4,300
Gasification and Gas Cooling	6,300
Raw Gas Compression	2,800
Desulfurization and Dehydration	2,500
Sulfur Recovery and Tailgas Treatment	1,500
Shift Conversion and Methanol Synthesis	1,600
CO_2 Removal	700
Utility Systems	1,700
Waste Disposal Terminal	500
Methyl Fuel Storage	900
Interconnecting Piping	1,500
Gas Transmission	4,500
Gas Distribution	–
Retrofit Equipment	4,300
Total Direct Cost	36,700
Distributables	4,100
Total Field Cost	40,800
Engineering and Fee	4,500
Total Construction Costs	45,300
Startup Cost	5,000
Total Capital Cost	50,300

Table 7-3

CAPITAL COSTS OF DIRECT COAL-FIRED
STEAM SYSTEM FOR CAMP PENDLETON
(Fourth Quarter 1977 Dollars)

Two Boiler and Scrubber Trains, Each Consuming 250 x 10^6 Btu/hr of Coal	Cost Thousands of Dollars
Coal Receiving and Preparation	4,900
Pulverized Coal Boiler	10,800
Electrostatic Precipitator	900
Stack Gas Scrubber	6,000
Steam Transmission	42,800
Steam Distribution	7,600
Retrofit Equipment	4,700
Total Direct Cost	77,700
Distributables	5,300
Total Field Cost	83,000
Engineering and Fee	9,100
Total Construction Cost	92,100
Startup Cost	10,100
Total Capital Cost	102,200

Table 7-4

SUMMARY OF TOTAL CAPITAL COSTS
OF ALTERNATIVE SYSTEMS FOR FIVE BASES

(Fourth Quarter 1977 Dollars)

Base	Peak Day Average, Total Heat Output,* 10^6 Btu/hr	Cost Thousands of Dollars		
		Gasification	Gas and Methyl Fuel	Direct Coal-Fired Boiler
Camp Pendleton	256	70,500	50,300	102,200
Mechanicsburg	246	37,700	—	25,300
Great Lakes	304	42,600	—	25,000
Norfolk	600	61,700	—	48,200
Quantico	366	49,300	—	41,000

*Total heat output is heat transferred in existing boilers and heaters.

Table 7-5

ANNUAL OPERATING COSTS
FOR ALTERNATIVES AT CAMP PENDLETON

(Thousands of Fourth Quarter 1977 Dollars)

	Cost		
82.4×10^6 Btu/hr Average Output*	Gasification	Gas and Methyl Fuel	Direct Coal-Fired Boiler
Coal	1,342	1,500	1,389
Electricity	342	1,000	188
Chemicals, Catalysts	40	60	67
Equipment, Supplies, Utilities	40	80	—
Operating Labor	590	760	—
Maintenance Material and Labor	900	1,000	—
Operating and Maintenance Material and Labor	—	—	840
Waste Disposal Subcontract	135	135	135
Liquid Fuel Delivery System	—	165	—
Total Annual Operating Cost	3,389	5,100	2,619
Tons of Coal per Year	53,680	60,000	55,560
Megawatt-Hours per Year	9,913	28,985	5,449
Tons of Solid Waste per Year	17,353	19,396	20,269
Service Factor	.32	.90	.32

*Output is heat transferred in existing heaters and boilers.

Table 7-6 summarizes the annual operating costs for the systems studied at all five bases. Detailed breakdowns for the other four bases are provided by Tables E-3 and E-4 in Appendix E.

LIFE CYCLE COSTS

Life cycle project present values were calculated for each case studied, following the methods of Reference (2), and using energy escalation rates suggested in Reference (3) and specified by Reference (4). Plant life begins January 1982 and lasts 28 years, as suggested in Reference (5).

Life cycle costs at Camp Pendleton for gasification are given in Table 7-7, for methyl fuel in Table 7-8, and for a direct coal-fired boiler system in Table 7-9.

Tables 7-7 to 7-9 include discount factors based on a discount rate of 10 percent per year after general inflation has been subtracted. If the rate of general inflation is eight percent per year, the actual discount rate would be 18 percent, which is the annual capital charge currently experienced by many public utilities.

Table 7-10 summarizes the present values for all five bases for the cases studied. Detailed present value calculations for the four other bases are presented in Tables E-5 and E-6 of Appendix E.

The life cycle costs can also be expressed in terms of present value per energy unit, by dividing the total project present value by the number of millions of Btu of energy consumed over the life of the project. Table 7-11 presents these costs for gasification and methyl fuel cases in terms of fuels manufactured. Table 7-12 presents the unit costs in terms of heat transferred or steam generated. To get the amount of heat transferred in boilers or heaters, the annual average current fuel consumption from Table 6-1 was multiplied by 0.8.

CONCLUSIONS

The following conclusions can be drawn from the comparisons above.

Table 7-6

SUMMARY OF ANNUAL OPERATING COSTS
OF ALTERNATIVE SYSTEMS AT FIVE BASES
(Fourth Quarter 1977 Dollars)

	Annual Average Hourly Heat Output,* 10^6 Btu/hr	Category	Cost Thousands of Dollars		
			Gasification	Gas and Methyl Fuel	Direct Coal-Fired Boiler
Camp Pendleton	83	Coal	1,342	1,500	1,389
		Electricity	342	1,000	188
		Other **	1,705	2,200	1,042
Mechanicsburg	34	Coal	560	-	445
		Electricity	142	-	60
		Other **	1,141	-	408
Great Lakes	82	Coal	1,330	-	1,047
		Electricity	339	-	141
		Other **	1,437	-	748
Norfolk	215	Coal	3,508	-	2,760
		Electricity	894	-	371
		Other **	2,761	-	2,412
Quantico	126	Coal	2,069	-	1,746
		Electricity	528	-	227
		Other **	1,551	-	984

* Heat output equals heat transferred in existing boilers and heaters.

** Other operating costs include catalysts and chemicals; equipment, supplies, and utilities; operating labor; maintenance material and labor; and waste disposal subcontract.

Table 7-7

LIFE CYCLE COSTS, GASIFICATION AT CAMP PENDLETON

Line Number	Cost Element	Differential Inflation Rate	Project Year	Amount, Thousands of Dollars		Discount Factor	Present Value Thousands of Dollars
				One Time	Recurring		
(1)	First Year Construction	+0	2	11,750		.867	10,187
(2)	Second Year Construction	+0	3	23,500		.788	18,518
(3)	Third Year Construction	+0	4	35,250		.717	25,274
(4)	Total Investment			70,500			53,979
(5)	Coal	+5	5-32		1,342	12.992	17,448
(6)	Electricity	+7	5-32		342	17.451	5,968
(7)	Operating and Maintenance Labor and Materials	+0	5-32		1,705	6.666	11,366
(8)	Total Operating Cost				3,389		34,782
(9)	Total Project Present Value						88,761

Table 7-8

LIFE CYCLE COSTS, GAS AND METHYL FUEL AT CAMP PENDLETON

Line Number	Cost Element	Differential Inflation Rate	Project Year	Amount, Thousands of Dollars		Discount Factor	Present Value Thousands of Dollars
				One Time	Recurring		
(1)	First Year Construction	+0	2	8,383		.867	7,283
(2)	Second Year Construction	+0	3	16,767		.788	13,238
(3)	Third Year Construction	+0	4	25,150		.717	18,000
(4)	Total Investment			50,300			38,521
(5)	Coal	+5	5-32		1,500	12.992	19,488
(6)	Electricity	+7	5-32		1,000	17.451	17,451
(7)	Operating and Maintenance Labor and Materials	+0	5-32		2,200	6.666	14,665
(8)	Total Operating Cost				4,700		51,604
	Total Project Present Value						90,125

Table 7-9

LIFE CYCLE COSTS, DIRECT COAL-FIRED BOILER PLANT

Line Number	Cost Element	Differential Inflation Rate	Project Year	Amount, Thousands of Dollars		Discount Factor	Present Value Thousands of Dollars
				One Time	Recurring		
(1)	First Year Construction	+0	2	17,033		.867	14,768
(2)	Second Year Construction	+0	3	34,067		.788	26,845
(3)	Third Year Construction	+0	4	51,100		.717	36,639
(4)	Total Investment			102,200			78,252
(5)	Coal	+5	5-32		1,389	12.992	18,046
(6)	Electricity	+7	5-32		188	17.451	3,281
(7)	Operating and Maintenance Labor and Materials	+0	5-32		1,042	6.666	6,977
(8)	Total Operating Cost				2,619		28,304
(9)	Total Project Present Value						106,556

Table 7-10

PRESENT VALUES OF ALTERNATIVES AT FIVE BASES
(Thousands of Fourth Quarter 1977 Dollars)

Process	Item	Camp Pendleton	Mechan-icsburg	Great Lakes	Norfolk	Quantico
Gasification	Capital	53,979	28,866	32,618	47,242	37,746
	Operating	34,782	17,016	31,953	77,417	45,212
	Total	88,761	45,882	64,571	124,659	82,958
Gas and Methyl Fuel	Capital	38,521				
	Operating	51,604				
	Total	90,125				
Direct Coal-Fired Boilers	Capital	78,252	19,372	19,142	36,906	31,393
	Operating	28,304	9,403	20,708	57,513	32,666
	Total	106,556	28,775	39,850	94,419	64,059
Maximum Heat Output,* 10^6 Btu/hr		256	246	304	600	366
Annual Average Heat Output,* 10^6 Btu/hr		83	34	82	215	126
Load Factor		.32	.14	.27	.36	.34

*Heat output is heat transferred or heat of steam generated in existing boilers and heaters.

Table 7-11

PRODUCT UNIT PRESENT VALUES AT FIVE BASES
GASIFICATION AND GAS PLUS METHYL FUEL

	Camp Pendleton	Mechan-icsburg	Great Lakes	Norfolk	Quantico
Gasification					
Present Value, 10^3 Dollars	88,761	45,882	64,571	124,659	82,958
Fuel Produced in 28 Years, 10^9 Btu	25,263	10,125	23,042	60,847	36,177
Product Unit Present Value, $\$/10^6$ Btu	3.51	4.53	2.80	2.05	2.28
Gas Plus Methyl Fuel					
Present Value, 10^3 Dollars	90,125				
Fuel Produced in 28 Years, 10^9 Btu	25,263				
Product Unit Present Value, $\$/10^6$ Btu	3.57				
Fuel Oil Alternative					
Unit Present Value, $\$/10^6$ Btu*	2.11	2.11	2.11	2.11	2.11

* Fuel oil alternative unit present value is the product:

$$X \cdot Y \cdot (1/Z)$$

where

X = $2.90/$10^6$ Btu fourth quarter 1977 fuel oil price
Y = 20.339 discount factor for 5th through 32nd project year with 8 percent annual differential escalation
Z = 28 years project life

Table 7-12

HEAT OUTPUT UNIT PRESENT VALUES AT FIVE BASES FOR ALL ALTERNATIVES*

	Camp Pendleton	Mechanicsburg	Great Lakes	Norfolk	Quantico
Gasification					
Present Value, 10^3 Dollars	88,761	45,882	64,571	124,659	82,958
Heat Output in 28 Years, 10^9 Btu	20,263	8,100**	18,042**	48,678**	28,942**
Heat Unit Present Value, $/$10^6$ Btu	4.38	5.66	3.58	2.56	2.85
Gas Plus Methyl Fuel					
Present Value, 10^3 Dollars	90,125				
Heat Output in 28 Years, 10^9 Btu	20,263				
Heat Unit Present Value, $/$10^6$ Btu	4.46				
Direct Coal Fired Boilers					
Present Value, 10^3 Dollars	106,556	28,775	39,850	94,419	64,059
Steam Output in 28 Years, 10^9 Btu	20,263	8,437	19,590	52,784	31,004
Steam Unit Present Value, $/$10^6$ Btu	5.26	3.41	2.03	1.79	2.07
Fuel Oil Alternative					
Heat Output Unit Present Value, $/$10^6$ Btu	2.64	2.64	2.64	2.64	2.64

* Heat output equals heat transferred in existing load heat exchangers, or heat of steam delivered to existing or equivalent load heat exchangers.

** The output for gasification is lower than for direct coal fired boilers for this base because the single train gasification plant has lower availability than the two-train boiler alternative.

Camp Pendleton

A central direct coal-fired boiler system is more expensive than a gasification or methyl fuel system. The major reasons for the high cost of the direct coal-fired boiler system at Camp Pendleton are the following:

- The high transmission, distribution, and retrofit capital costs (two-thirds of the total capital costs)
- The large thermal losses in the steam transmission lines (which increase the coal consumption by 30 percent over a zero-loss consumption)

Methyl fuel is slightly more expensive than gasification. The load factor of the gasification plant is 31 percent. This turns out to be high enough to make the methyl fuel alternative slightly more expensive. However, the difference between methyl fuel and gasification present values is small, and the choice between the two might be made on the basis of other considerations.

Continued use of fuel oil and natural gas would be less expensive than any coal option. However, if natural gas becomes unavailable, the housing currently served by natural gas would have to have oil-fired heaters and liquid fuel tanks installed.

Two alternative gasifications options — a no-storage option and an industrial-only option — were considered and costed out to see if gasification costs could be reduced in comparison with the nominal case already presented:

- The no-storage option is the nominal case minus the gas storage sphere. This option would result in inadequate heating during the 4-hour period on the coldest days.
- The industrial-only option is a single train 125×10^6 Btu/hr gasification plant serving the nonhousing heat loads on the base, with an average of 60×10^6 Btu/hr of medium-Btu gas. Fuel oil backup for the loads served is already available. Housing would remain on natural gas.

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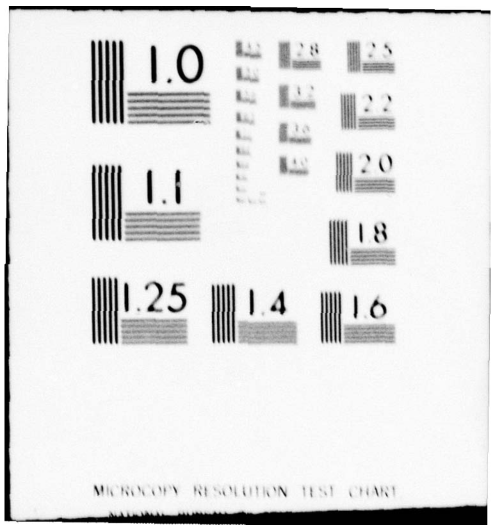
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Neither additional option is less expensive than fuel oil. Table 7-13 presents the costs for the options.

Table 7-13

PRODUCT UNIT PRESENT VALUES FOR
GASIFICATION ALTERNATIVES AT CAMP PENDLETON

	No-Storage Option	Industrial-Only Option	Nominal Case
Total Life Cycle Present Values, $\$/10^3$ Btu	84,810	49,635	88,761
Fuel Produced in 28 Years, 10^9 Btu	25,263	13,481	25,263
Product Unit Present Value, $\$/10^6$ Btu	3.36	3.68	3.51
Load Factor	.32	.44	.32

Mechanicsburg

A central direct coal-fired system is less expensive than gasification.

Continued use of fuel oil is less expensive than either coal option.

Great Lakes

A direct coal-fired boiler system is less expensive than a gasification or fuel oil system.

The recent engineering study for Great Lakes recommended a coal-fired boiler system which cost 33 million in 1980 dollars. This included a $7 million tunnel for coal conveyance. If a tunnel is added to Bechtel's direct coal-fired configuration for Great Lakes ($6 million de-escalated), the total capital required would be $30 million, and the total present value would be $43.8 million, still less than both gasification and fuel oil burning.

Gasification is more expensive than fuel oil.

Norfolk

A direct coal-fired boiler system is less expensive than a gasification or fuel oil system.

Gasification is less expensive than fuel oil when the gasification plant has only one train. However, a two-train plant may be more expensive than fuel oil.

A recent engineering recommendation for Norfolk to utilize existing coal convertible boilers would cost approximately $16 million (stack gas scrubbers were not included). Thus, a direct coal-fired boiler alternative exists for Norfolk which is even lower in cost than the all-new system priced out by Bechtel.

Quantico

A central direct coal-fired boiler system is less expensive than a gasification or fuel oil system.

Section 8

RECOMMENDATIONS

The following recommendations are prepared as a follow-up to the present study:

- A design optimization study for a coal gasification plant at Camp Pendleton should be performed to provide a better basis for decision. Such a study would reveal more cost details related to the following:
  - Load distribution
  - Existing and new gas piping
  - Process alternatives
  - Site and layout
  - Optimized conditions
- The Navy should investigate decentralized direct coal-fired boilers plus scrubbers at Camp Pendleton as an alternative not covered in the present study.

Section 9

REFERENCES

(1) "Coal Gasification Study," Bechtel Corporation, April 1977, Contract N68305-76-C-0009, CEL Publication CR 77.013, NTIS Publication A014860.

(2) "Economic Analysis Handbook, " P-442, Naval Facilities Engineering Command, 1975.

(3) "Assessment of Availability and Price of Fossil Fuels for Utility Purposes through 1985," Hoffman-Muntner Corporation, June 1975.

(4) "Energy Escalation Rates for Short Term Costing and Life Cycle Costing," NAVFACENGCOM Ltr 1023B/JNW of 23 August 1976.

(5) SECNAVINST 4860 44A, "Commercial or Industrial Activities Program," 27 October 1971.

(6) "ASHRAE Handbook and Product Directory: Fundamentals," American Society of Heating, Refrigerating and Air Conditioning Engineers, Inc., New York, 1977.

(7) "Engineering Weather Data," P-89, Naval Facilities Engineering Command, 1967.

Appendix A

GASIFICATION FOR CENTRAL STEAM

At the end of Section 2, it was stated that it was not economical to install a coal gasification plant if the gas was to be injected directly into a new gas-fired central steam plant. The reader can verify this by using Tables C-1 and C-2. The totals of transmission, distribution, and retrofit costs for the central boiler case were higher than those for the gasification case, at each base. The totals for the gasification plant, excluding transmission, distribution, and retrofit, were higher than those for the central boiler case. Gasification for central steam would lead to a combination of the highest cost aboveground plant and the highest cost transmission, distribution, and retrofit facilities.

Appendix B

ENVIRONMENTAL SULFUR LIMITS

The gasification plants and the direct coal-fired boiler plants considered in this study have been designed to remove 70 percent of the sulfur compounds from a 2 percent sulfur coal. The resulting sulfur emissions are 1.2 pounds of SO_2 per million Btu. The same equipment can achieve higher percentages of sulfur removal with no increase in capital costs and only small increases in operating costs. Below, federal and local sulfur emission standards are described. The most stringent applicable standards apply.

FEDERAL STANDARDS

Amendments in 1977 to the Clean Air Act have called for more stringent New Source Performance Standards. The Environmental Protection Agency has prepared a draft of proposed new standards, and is currently working out a final set of standards for official enforcement.

According to the EPA draft, the standards would apply to the following:

- Steam generators located in a facility where more than one-third of the steam is ultimately used to produce electricity for sale
- Steam generators that fire more than 250 million Btu/hr of heat input.

Since most existing boilers are below 250 million Btu/hr, and since no power is exported, these facilities are not subject to current federal regulations. However, in the future, similar regulations may be extended to include these facilities.

According to the EPA draft, the standards would limit SO_2 emissions from coal-fired boilers as follows:

- Uncontrolled emissions (emissions equivalent to the sulfur content of untreated coal, as mined) must be reduced by 90 percent.
- The 90 percent reduction need not be achieved if emissions to the atmosphere are less than 0.2 pounds of SO_2 per million Btu, on the average, over 24 hours.
- The maximum allowable emissions under any circumstances are 1.2 pounds of SO_2 per million Btu, on the average, over 24 hours.

LOCAL STANDARDS

Camp Pendleton

Camp Pendleton is covered by the regulations of the San Diego Air Pollution Control District. Regulations from this district are as follows:

- Solid and liquid fuels may be burned in existing facilities without control if they contain less than 0.5 percent sulfur.
- Any new source producing less than 100 pounds of SO_2 per day and less than 10 pounds per hour can be uncontrolled.
- Any new source producing more than 250 pounds of SO_2 per day or more than 20 pounds per hour must be reviewed by the control district, and may be required to apply the best available control technology.

Mechanicsburg

The Ships Parts Control Center lies within the municipality of Mechanicsburg, which has a limit of 4 pounds of SO_2 per 10^6 Btu of fired coal.

Harrisburg, Pennsylvania, is in an air basin with a limit of 2.35 pounds of SO_2 per 10^6 Btu.

Great Lakes

Both gasification and direct coal firing would be controlled to 1.8 pounds of SO_2 per 10^6 Btu.

Norfolk

Coal burning boilers at Norfolk Naval Base would be limited to 2.64 pounds of SO_2 per million Btu.

Quantico

Quantico coal consuming sources would be limited to 1.06 pounds of SO_2 per million Btu of coal heating value.

Appendix C

GASPLANT COMPUTER PROGRAM

The Coal Technology Department of Bechtel Corporation's Research and Engineering has developed a computer program for modeling coal gasification plant stream flows, utilities, equipment sizing, and capital costs. The computer routine, called Program GASPLANT was built to perform conceptual design calculations. Program GASPLANT produces a readable five-part readout dealing with the gasifier, main plant streams, utility streams, the check on mass and heat balances, and costs.

The program calculates the composition and emergence temperature of the gas produced in high temperature gasification. This calculation takes into account the thermodynamic equilibrium between CO, H_2, CO_2, H_2O, and CH_4 at the exit temperature predicted by a rigorous heat balance. Special condition settings appropriate to commercial entrained bed and fluidized bed gasifiers are incorporated.

The program explicitly calculates the composition and total flow of each of 55 streams in a representative H_2S scrubbing and sulfur recovery complex. The H_2S removal module uses equilibrium data on M-Pyrol to describe the simultaneous absorption of H_2S, COS, CO_2, and H_2O and subsequent processing in a module containing four separation towers, 11 heat exchangers and a two-stage compressor. Heat and material balances for a Claus sulfur recovery plant and a SCOT tailgas treating plant are calculated.

The program also has a special utility subroutine that automatically sizes cooling towers, boiler feed water treatment facilities, and cooling water

and condensate pumps and decides whether auxiliary boilers are needed. The utility routine totals the steam, electricity, cooling, and plant fuel services needed by a particular plant and tabulates the heat and mass flow to each plant unit needing service.

A cost package is included in the program that produces component cost details and totals for capital and operating costs in the same form as generated by Bechtel cost engineers. Costs of 16 common plant equipment and plant module types are generated automatically in terms of capacity and other relevant parameters.

A special subroutine has been built to check and assure mass and energy balances over each plant unit. Program GASPLANT places at the programmer's disposal an intelligible collection of Fortran subroutine calls for describing a particular plant. This exclusive Bechtel methodology has been given the name FLOWLANG. FLOWLANG plant descriptions are unusually easy to follow because each of 29 allowed chemical species has its chemical formula or a common name as its global Fortran variable name. For instance, CO_2 designates the molar flow of carbon dioxide in a stream under consideration. This methodology has been used to create a description of the gasification plants considered in the present study.

The most advanced version of Program GASPLANT is available on Bechtel's UNIVAC 1110 computer system. The Fortran coding occupies 70,000 words of disc storage, and the compiled program occupies 60,000 words of core on the Univac 1110. A run takes less than a minute. Program GASPLANT is ideal for optimization studies in which the least cost configuration is sought, and for design studies requiring frequent updating of the flow diagram.

Appendix D

CALCULATION OF PEAK AND AVERAGE HEATING LOADS

The consumption and weather data method was used in Section 6 for computing the correct size for new coal consuming facilities at each of the five bases. This appendix presents details on the calculation method.

The purpose of the calculation is to predict for each base the space heating requirement on the coldest day of the winter, based on the space heating that is actually used on the average during the coldest month of the winter.

COLDEST DAY AND COLDEST MONTH TEMPERATURES

Chapter 23 of the ASHRAE 1977 Fundamentals Handbook (Reference 6) lists temperatures commonly used for design at locations near the basis studied. The more detailed temperature data in the NAVFAC Engineering Weather Data manual (Reference 7) lists design temperatures at the bases. It also gives temperature frequency data at nearby weather stations. This frequency information includes month by month tabulations for each of three daily periods:

- Sleep — 0101 to 0900 hours
- Work — 0901 to 1700 hours
- Recreation — 1701 to 0100 hours

The frequency tabulations were used to determine two temperatures during each of the three periods in January:

- A 97.5 percent temperature,* used in this report as the "coldest day" temperature
- A 50 percent temperature, used in this study as the "coldest month" temperature

The average "coldest day" temperature was tabulated in Table 6-3. The following table gives the six temperatures for one base.

Table D-1

CAMP PENDLETON JANUARY TEMPERATURES

Period	Coldest Day Temperature	Coldest Month Temperature
0101 to 0900	26	42
0901 to 1700	42	54
1701 to 0100	34	49

HEAT LOSS CALCULATION ASSUMPTIONS

Space heating energy replaces heat lost from buildings due to two processes:

- Transmission
- Infiltration

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*The January 97.5 percent temperature is the temperature which is equalled or exceeded 97.5 percent of the time during the period indicated in January. The average of these January 97.5 percent temperatures is close to the standard 97.5 percent design temperature, which is equalled or exceeded 97.5 percent of the time in the three months December, January, and February.

Transmission Losses

Heat is lost by heat conduction and convection through surfaces according to the equation

$$q_T = U\ A\ \Delta T,$$

where

q_T = Heat loss rate by transmission, Btu/hr

U = Overall heat transfer coefficient, Btu/hr ft^2 ^oF

A = Area of building surface, ft^2

ΔT = Temperature difference between inside and outside, ^oF

In this study, the following assumptions were followed:

- The overall heat transfer coefficient U for each building is the same on the coldest day as on the average during January*
- The surface area A for each building is the same

Since U and A are constant, the heat loss by transmission is directly proportional to ΔT.

Infiltration

Air entering through ventilation ports, windows, and cracks is referred to as infiltration. The heat required to heat up cold air entering in this way is given by

$$q_I = Q\ Cp\ \Delta T$$

where

q_I = Heat loss by infiltration, Btu/hr

Q = Rate of air infiltration, ft^3/hr

Cp = Heat capacity of air, Btu/ft^3 ^oF

ΔT = Temperature difference between inside and outside, ^oF

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*The constant U assumption corresponds to assuming that the effect of changes in outer surface air film heat transfer coefficient, h, is negligible or to assuming that the wind conditions are the same in the two cases. The air film coefficient h would vary with changes in wind velocity.

In this study, the following assumptions were made:

- The rate of infiltration Q is the same on the coldest day as on the average during January, for each building on the base*
- The heat capacity Cp is constant.

With Q and Cp constant, the heat loss by infiltration is directly proportional to ΔT.

Total Heat Losses

The total rate of heat loss is the sum of transmission and infiltration loss rates. Since both of these are proportional to ΔT, the total loss rate is proportional to ΔT. The difference ΔT between the temperature inside a building and that of the air outside the building is referred to in the heating industry as the "degrees of heating".

DEGREES OF HEATING

The ratio of the heat duty on the coldest day to the average heat duty in the coldest month is assumed directly proportional to the ratio of the coldest day degrees of heating to the average coldest month degrees of heating.

A sample calculation of this ratio for Camp Pendleton is shown in Table D-2, using the outside temperatures of Table D-1 and the building inside temperatures of Table 6-4.

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*The constant Q assumption is reasonable if infiltration is mainly due to wind pressure, and if wind velocities are the same on the coldest day as on the average in January.

Table D-2

CALCULATION OF CAMP PENDLETON DEGREES OF HEATING

Building Service	Daily Period	Coldest Day Degrees	Coldest Month Degrees
Domestic	0101 to 0900	(70-26)=44	(70-42)=28
	0901 to 1700	(70-42)=28	(70-54)=15
	1701 to 0100	(70-34)=36	(70-49)=21
	$3 \cdot \Delta T$	108	63
	ΔT	36	21.5
Work Spaces	0501 to 0900	(70-26)=44	(70-42)=28
	0901 to 1700	2 · (70-42)=56	2 · (70-54)=32
	1701 to 0100	2 · (50-34)=32	2 · (50-49)= 2
	0101 to 0500	(50-26)=24	(50-42)= 8
	$6 \cdot \Delta T$	158	70
	ΔT	26	11.5

Building Service	Weighting Factors		
Domestic	.5	.5·(36)= 18	.5·(21.5)= 10.75
Work Spaces	.5	.5·(26)= 13	5.75
Degrees of Heating		31	16.6

Ratio: Coldest Day/Coldest Month = 31/16.5= 1.88

PEAK DAY HEATING DUTY

The ratio of coldest day heating duty to coldest month heating duty calculated in Table D-2 is 1.88 for Camp Pendleton. The worst month heating duty at Camp Pendleton is 170×10^6 Btu/hr according to Table 6-2. The calculated worst day (peak day) heating duty is therefore

$$(1.88)\ (170 \times 10^6) = 320 \times 10^6,$$

as shown in Table 6-2.

Appendix E

CAPITAL, OPERATING, AND LIFE CYCLE COST DETAILS

This appendix includes tables on capital, operating and life cycle costs.

The following are some notes about the contents of the tables:

- Each capital cost entry contains an allowance for uncertainty. This allowance is one-sixth of the amount of the entry.

- The "distributables" capital cost entry allows for temporary roads, shelters, and improvements used during construction and dismantled afterwards. The "distributables" entry includes costs of this type which are incurred by the prime contractor. Subcontracted modules include a share for distributables in the subcontract price. Modules priced as subcontracts are the following:

  - Gasification plants: coal receiving and preparation, oxygen supply, gasification and gas cooling, sulfur recovery and tailgas treatment, temporary waste disposal terminal, and gas storage.

  - Direct coal-fired boiler plants: coal receiving and preparation, boiler, electrostatic precipitator, and stack gas scrubber.

- For direct coal fired boiler plants, operating and maintenance labor and materials are combined into a single total, since available boiler and scrubber annual cost statistics are more consistent in this form.

- Present values are computed with the discount factors shown in Tables 7-7 through 7-9, except for electricity, as shown in Tables E-5 and E-6.

Table E-1

CAPITAL COST DETAILS, GASIFICATION AT FIVE BASES
(Thousands of Fourth Quarter 1977 Dollars)

	Camp Pendleton	Mechan-icsburg	Great Lakes	Norfolk	Quantico
Coal Receiving and Preparation	4,500	4,500	4,900	6,500	5,300
Oxygen Supply	10,200	7,400	8,300	12,100	9,100
Gasification and Gas Cooling	13,100	8,300	9,000	11,500	10,000
Raw Gas Compression	3,100	2,400	2,800	4,400	3,100
Desulfurization and Dehydration	2,200	1,500	1,800	3,000	2,100
Sulfur Recovery and Tailgas Treatment	2,900	1,500	1,500	2,300	1,700
Interconnecting Piping	2,100	1,700	2,000	3,100	2,100
Utilities	1,000	700	800	1,100	800
Waste Disposal Terminal	600	500	600	800	600
Gas Storage	4,000	-	-	-	-
Gas Transmission	6,700	250	480	1,000	1,900
Gas Distribution	200	100	20	50	50
Retrofit Equipment	2,800	150	600	1,650	1,450
Total Direct Cost	53,400	29,000	32,800	47,500	38,200
Distributables	3,800	1,600	1,800	2,600	1,800
Total Field Cost	57,200	30,600	34,600	50,100	40,000
Engineering and Fee	6,300	3,400	3,800	5,500	4,400
Total Construction Cost	63,500	34,000	38,400	55,600	44,400
Startup Cost	7,000	3,700	4,200	6,100	4,900
Total Capital Cost	70,500	37,700	42,600	61,700	49,300
Number of Process Trains	2	1	1	1	1
Gas Output per Train, 10^6 Btu/hr	160	308	380	750	458

Table E-2

CAPITAL COST DETAILS, DIRECT COAL-FIRED BOILER SYSTEMS
AT FIVE BASES
(Thousands of Fourth Quarter 1977 Dollars)

	Camp Pendleton	Mechan-icsburg	Great Lakes	Norfolk	Quantico
Coal Receiving and Preparation	4,900	4,000	4,300	6,000	4,600
Pulverized Coal Boilers	10,800	7,200	8,700	15,100	10,000
Electrostatic Precipitator	900	600	700	1,400	800
Stack Gas Scrubber	6,000	4,300	4,800	8,600	5,700
Steam Transmission	42,800	1,200	1,680	4,800	9,000
Steam Distribution	7,600	400	20	1,600	1,300
Retrofit Equipment	4,700	2,600	-	1,000	1,000
Direct Field Cost	77,700	20,300	20,200	38,500	32,400
Distributables	5,300	200	100	600	800
Total Field Cost	83,000	20,500	20,300	39,100	33,200
Engineering and Fee	9,100	2,300	2,200	4,300	3,700
Total Construction Cost	92,100	22,800	22,500	43,400	36,900
Startup Cost	10,100	2,500	2,500	4,800	4,100
Total Capital Cost	102,200	25,300	25,000	48,200	41,000
Number of Trains	2	2	2	2	2
Total Coal Used Maximum, 10^6 Btu/hr	500	313	388	762	488

Table E-3

ANNUAL OPERATING COST DETAILS
GASIFICATION AT FIVE BASES
(Thousands of Fourth Quarter 1977 Dollars)

	Camp Pendleton	Mechan-icsburg	Great Lakes	Norfolk	Quantico
Coal	1,342	560	1,330	3,508	2,069
Electricity	342	142	339	894	528
Catalysts and Chemicals	40	17	40	105	63
Equipment, Supplies, Utilities	40	17	40	105	63
Operating Personnel	590	390	460	920	432
Maintenance Materials and Labor	900	590	760	1,370	921
Waste Disposal Subcontract	135	127	137	261	170
Total	3,389	1,843	3,106	7,163	4,198
Tons of Coal per Year	53,680	22,400	53,200	140,320	82,760
Megawatt-Hours per Year	9,913	4,152	9,912	26,140	15,438
Tons of Solid Waste per Year	17,353	7,241	17,197	45,360	26,754
Annual Average Heat Output, 10^6 Btu/hr	83	34	82	215	126
Service Factor	.32	.14	.27	.36	.34

Table E-4

ANNUAL OPERATING COST DETAILS,
DIRECT COAL-FIRED BOILERS AT FIVE BASES
(Thousands of Fourth Quarter 1977 Dollars)

	Camp Pendleton	Mechanicsburg	Great Lakes	Norfolk	Quantico
Coal	1,389	445	1,047	2,760	1,746
Electricity	188	60	141	371	227
Lime	67	21	50	132	81
Maintenance and Operating Materials and Labor	840	260	561	2,060	733
Waste Disposal Subcontract	135	127	137	220	170
Total	2,619	913	1,936	5,543	2,957
Tons of Coal per Year	55,560	17,800	41,880	110,400	69,840
Megawatt Hours per Year	5,362	1,754	4,123	10,848	6,637
Tons of Solid Waste per Year	20,269	6,494	15,278	40,276	25,479
Annual Average Heat Output, 10^6 Btu/hr	83	34	82	215	126

Table E-5

PRESENT VALUES FOR GASIFICATION AT FIVE BASES
(Thousands of Fourth Quarter 1977 Dollars)

	Camp Pendleton	Mechan-icsburg	Great Lakes	Norfolk	Quantico
First Year Construction	10,187	5,448	6,156	8,916	7,124
Second Year Construction	18,518	9,903	11,190	16,207	12,948
Third Year Construction	25,274	13,515	15,272	22,119	17,674
Total Investment	53,979	28,866	32,618	47,242	37,746
Coal	17,448	7,276	17,279	45,576	26,883
Electricity *	5,968	2,134	5,095	13,436	7,930
Operating and Maintenance Labor and Material	11,366	7,606	9,579	18,405	10,399
Total Operating Cost	34,782	17,016	31,953	77,417	42,212
Total Life Cycle Present Value	88,761	45,882	64,571	124,659	82,958

*Electricity Differential Escalation	+7	+6	+6	+6	+6
Electricity Discount Factor	17.451	15,029	15.029	15.029	15.029

Table E-6

PRESENT VALUES FOR DIRECT COAL-FIRED BOILERS AT FIVE BASES
(Thousands of Fourth Quarter 1977 Dollars)

	Camp Pendleton	Mechan-icsburg	Great Lakes	Norfolk	Quantico
First Year Construction	14,768	3,656	3,612	6,965	5,925
Second Year Construction	26,845	6,646	6,567	12,661	10,769
Third Year Construction	36,639	9,070	8,963	17,280	14,699
Total Investment	78,252	19,372	19,142	36,906	31,393
Coal	18,046	5,781	13,603	35,858	22,686
Electricity*	3,281	902	2,119	5,576	3,418
Operating and Maintenance Labor and Material	6,977	2,720	4,986	16,079	6,562
Total Operating Cost	28,304	9,403	20,708	57,513	32,666
Total Life Cycle Present Value	106,556	28,775	39,850	94,419	64,059

*Electricity Differential Escalation	+7	+6	+6	+6	+6
Electricity Discount Factors	17.451	15.029	15.029	15.029	15.029